BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI‘I

------ In The Matter Of -----	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2014-0183
	)	
Instituting a Proceeding to Review the	)	
Power Supply Improvement Plans for	)	
Hawaiian Electric Company, Inc., Hawaii	)	
Electric Light Company, Inc., and Maui	)	
Electric Company, Limited.	)	
	)	

Hawaiian Electric Companies' PSIPs Update Report

Filed April 1, 2016

Book 2 of 2

K. Candidate Plan Data

Candidate plans are a method of analyzing the numerous resources and variables to ultimately arrive at the Preferred Plans. This appendix lists the candidate plans (cases) that Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric created and ran to develop the Preferred Plans.

HAWAIIAN ELECTRIC

Hawaiian Electric First Iteration Cases

Case Name	Case 1: 100% Renewable Reference Case	Case 1: 100% Renewable Reference Case
Case Label	15_IDR	15_IDR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Future PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Future PV Install 24MW NPM Wind
2019	90 MW Contingency BESS	90 MW Contingency BESS
2020	Install 50MW Future PV Install 100MW JBPHH Plant, 12/2020	Install 50MW Future PV Install 100MW JBPHH Plant, 12/2020
2021	Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021	Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021
2022	AES Deactivated 9/2022 Install 50MW Future Wind Install 50MW Future PV	
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Future Wind	Install 50MW Future Wind
2026		
2027		
2028	Install 50MW Future PV	Install 50MW Future PV
2029		
2030		
2031	Install 50MW Future PV	Install 50MW Future PV
2032		
2033	Install 50MW Future PV	Install 50MW Future PV
2034		
2035	Install 50MW Future PV	Install 50MW Future PV
2036	Install 50MW Future PV	Install 50MW Future PV
2037	Install 50MW Future Wind Install 50MW Future PV	Install 50MW Future Wind Install 50MW Future PV
2038	Install 50MW Future PV	Install 50MW Future PV
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-1. Hawaiian Electric First Iteration Cases (1 of 5)

Case Name	Case 2: 100% Renewable with Modernization	Case 2: 100% Renewable with Modernization
Case Label	15_2DR	15_2DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on Diesel, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on Diesel, 6/2021
2022	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Onshore Wind	Install 50MW Onshore Wind
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-2. Hawaiian Electric First Iteration Cases (2 of 5)

Case Name	Case 3: 100% Renewable with Transitional LNG Fuel	Case 3: 100% Renewable with Transitional LNG Fuel
Case Label	15_3DR	15_3DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020
2021	K1-6, KPLP: LNG, 1/2021 Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021	K1-6, KPLP: LNG, 1/2021 Waiau 3 & 4 Deactivated, 1/2021 Install 27 MW KMCBH Plant, 6/2021
2022	AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Onshore Wind	Install 50MW Onshore Wind
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD
2041		
2042		
2043		
2044		
2045		

Table K-3. Hawaiian Electric First Iteration Cases (3 of 5)

Case Name	Case 4: 100% Renewable with Modernization and Transitional LNG Fuel	Case 4: 100% Renewable with Modernization and Transitional LNG Fuel
Case Label	15_4DR	15_4DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020	Install 50MW Utility PV Install 100MW JBPHH Plant, 12/2020 K1-3 Deactivated 12/2020
2021	K5-6, KPLP: LNG, 1/2021 Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on LNG, 6/2021	K5-6, KPLP: LNG, 1/2021 Install 27 MW KMCBH Plant, 6/2021 Install 3x1CC on LNG, 6/2021
2022	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 50MW Onshore Wind	Install 50MW Onshore Wind
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD	LNG Contract ends 12/31/2040 Kahe Units on LNG switch to BioD KPLP switch to BioD
2041		
2042		
2043		
2044		

2045		

Table K-4. Hawaiian Electric First Iteration Cases (4 of 5)

Case Name	Case 5: 100% Renewable with Limited Modernization	Case 5: 100% Renewable with Limited Modernization
Case Label	15_5DR	15_5DR_LF
DER Forecast	Market	Market
Fuel Price	High	Low
2016	137.2 MW Waiver PV Projects added 12/31/2016	137.2 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind	Six -8.14 MW Schofield Plants added Install 25MW Utility PV Install 24MW NPM Wind
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 50MW Utility PV	Install 50MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 50MW Onshore Wind Install 50MW Utility PV
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 50MW Onshore Wind Kahe 6 Deactivated, 1/2025	Install 50MW Onshore Wind Kahe 6 Deactivated, 1/2025
2026		
2027		
2028	Install 50MW Utility PV	Install 50MW Utility PV
2029		
2030		
2031	Install 50MW Utility PV	Install 50MW Utility PV
2032		
2033	Install 50MW Utility PV	Install 50MW Utility PV
2034		
2035	Install 50MW Utility PV	Install 50MW Utility PV
2036	Install 50MW Utility PV	Install 50MW Utility PV
2037	Install 50MW Onshore Wind Install 50MW Utility PV	Install 50MW Onshore Wind Install 50MW Utility PV
2038	Install 50MW Utility PV	Install 50MW Utility PV
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-5. Hawaiian Electric First Iteration Cases (5 of 5)

Hawaiian Electric Second Iteration Cases

Case Name	Theme 1, Case 1: Aggressive Wind, No Storage	Theme 1, Case 2: Aggressive Wind, No Storage
Case Label	16_T1aWWH30_v0	16_T1aWWL30_v0
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind	Install 1600 MW Offshore Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-6. Hawaiian Electric Second Iteration Cases (1 of 47)

Case Name	Theme 1, Case 3: Aggressive Wind, Low Storage	Theme 1, Case 4: Aggressive Wind, Low Storage
Case Label	16_T1aWWH30_v2	16_T1aWWL30_v2
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind Install (2) 280 MW x 4 hr Energy Storage	Install 1600 MW Offshore Wind Install (2) 280 MW x 4 hr Energy Storage
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install (2) 100 MW x 4 hr Energy Storage	Install (2) 100 MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-7. Hawaiian Electric Second Iteration Cases (2 of 47)

Case Name	Theme 1, Case 5: Aggressive Wind, Medium Storage	Theme 1, Case 6: Aggressive Wind, Medium Storage
Case Label	16_T1aWWH30_v4	16_T1aWWL30_v4
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind Install (2) 1350 MW x 4 hr Energy Storage	Install 1600 MW Offshore Wind Install (2) 1350 MW x 4 hr Energy Storage
2026		
2027		
2028		
2029		
2030	Install (2) 150 MW x 4 hr Energy Storage	Install (2) 150 MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install (2) 100 MW x 4 hr Energy Storage	Install (2) 100 MW x 4 hr Energy Storage

Table K-8. Hawaiian Electric Second Iteration Cases (3 of 47)

Case Name	Theme 1, Case 7: Aggressive Wind, High Storage	Theme 1, Case 8: Aggressive Wind, High Storage
Case Label	16_T1aWWH30_v3	16_T1aWWL30_v3
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Install 1600 MW Offshore Wind Install (2) 1850 MW x 4 hr Energy Storage	Install 1600 MW Offshore Wind Install (2) 1850 MW x 4 hr Energy Storage
2026		
2027		
2028		
2029		
2030	Install (2) 200 MW x 4 hr Energy Storage	Install (2) 200 MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install (2) 100 MW x 4 hr Energy Storage	Install (2) 100 MW x 4 hr Energy Storage

Table K-9. Hawaiian Electric Second Iteration Cases (4 of 47)

Case Name	Theme 1, Case 9: Aggressive Solar	Theme 1, Case 10: Aggressive Solar
Case Label	16_T1aSSH30_v2	16_T1aSSL30_v2
DER Forecast	High	High
Fuel Price	High	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW Onshore Wind Install 360 MW Utility PV	Install 20MW Onshore Wind Install 360 MW Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54 MW KMCBH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025		
2026		
2027	Install 2820 MW Utility PV Install (2) 1450 MW x 4 hr Energy Storage	Install 2820 MW Utility PV Install (2) 1450 MW x 4 hr Energy Storage
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install (2) 80 MW x 4 hr Energy Storage	Install (2) 80 MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install (2) 40 MW x 4 hr Energy Storage	Install (2) 40 MW x 4 hr Energy Storage

Table K-10. Hawaiian Electric Second Iteration Cases (5 of 47)

Case Name	Theme 2, Case 11: Solar and Wind	Theme 2, Case 12: Solar and Wind
Case Label	16_T2aWv1L	16_T2aWv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		

2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-11. Hawaiian Electric Second Iteration Cases (6 of 47)

Case Name	Theme 2, Case 13: Solar and Wind	Theme 2, Case 14: Solar and Wind
Case Label	16_T2bWv1L	16_T2bWv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind	Install 1440MW of Utility PV Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-12. Hawaiian Electric Second Iteration Cases (7 of 47)

Case Name	Theme 2, Case 15: Solar	Theme 2, Case 16: Solar
Case Label	16_T2aSv1L	16_T2aSv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV	Install 2320MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-13. Hawaiian Electric Second Iteration Cases (8 of 47)

Case Name	Theme 2, Case 17: Solar	Theme 2, Case 18: Solar
Case Label	16_T2bSv1L	16_T2bSv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV	Install 2110MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-14. Hawaiian Electric Second Iteration Cases (9 of 47)

Case Name	Theme 2, Case 19: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 20: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2aWv1L40	16_T2aWv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 3100MW of Utility PV	Install 3040MW of Utility PV

Table K-15. Hawaiian Electric Second Iteration Cases (10 of 47)

Case Name	Theme 2, Case 21: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 22: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2bWv1L40	16_T2bWv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 3040MW of Utility PV	Install 3040MW of Utility PV

Table K-16. Hawaiian Electric Second Iteration Cases (11 of 47)

Case Name	Theme 2, Case 23: Solar, HL and ME 100% RE 2040	Theme 2, Case 24: Solar, HL and ME 100% RE 2040
Case Label	16_T2aSv1L40	16_T2aSv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 440MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 280MW of Utility PV	Install 280MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 2320MW of Utility PV	Install 2360MW of Utility PV

Table K-17. Hawaiian Electric Second Iteration Cases (12 of 47)

Case Name	Theme 2, Case 25: Solar, HL and ME 100% RE 2040	Theme 2, Case 26: Solar, HL and ME 100% RE 2040
Case Label	16_T2bSv1L40	16_T2bSv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 560MW of Utility PV	Install 560MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1460MW of Utility PV	Install 1460MW of Utility PV

Table K-18. Hawaiian Electric Second Iteration Cases (13 of 47)

Case Name	Theme 2, Case 27: Solar and Wind, with Storage	Theme 2, Case 28: Solar and Wind, with Storage
Case Label	16_T2aWv1LBf	16_T2aWv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage
2041		
2042		
2043		

2044		
2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-19. Hawaiian Electric Second Iteration Cases (14 of 47)

Case Name	Theme 2, Case 29: Solar and Wind, with Storage	Theme 2, Case 30: Solar and Wind, with Storage
Case Label	16_T2bWv1LBf	16_T2bWv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-20. Hawaiian Electric Second Iteration Cases (15 of 47)

Case Name	Theme 2, Case 31: Solar, with Storage	Theme 2, Case 32: Solar, with Storage
Case Label	16_T2aSv1LBf	16_T2aSv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 620MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-21. Hawaiian Electric Second Iteration Cases (16 of 47)

Case Name	Theme 2, Case 33: Solar, with Storage	Theme 2, Case 34: Solar, with Storage
Case Label	16_T2bSv1LBf	16_T2bSv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 890MW of Utility PV Install (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV Install (10) 100MW x 4 hr Energy Storage	Install 2110MW of Utility PV Install (10) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-22. Hawaiian Electric Second Iteration Cases (17 of 47)

Case Name	Theme 2, Case 35: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 2, Case 36: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T2aWv1LBf40	16_T2aWv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 340MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind Install (2) 100MW x 4 hr Energy Storage	Install 400MW of Offshore Wind Install (2) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 3100MW of Utility PV	Install 3040MW of Utility PV

Table K-23. Hawaiian Electric Second Iteration Cases (18 of 47)

Case Name	Theme 2, Case 37: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 2, Case 38: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T2bWv1LBf40	16_T2bWv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind Install (1) 100MW x 4 hr Energy Storage	Install 400MW of Offshore Wind Install (1) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 3040MW of Utility PV	Install 3040MW of Utility PV

Table K-24. Hawaiian Electric Second Iteration Cases (19 of 47)

Case Name	Theme 2, Case 39: Solar, with Storage, HL and ME 100% RE 2040	Theme 2, Case 40: Solar, with Storage, HL and ME 100% RE 2040
Case Label	16_T2aSv1LBf40	16_T2aSv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 400MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 440MW of Utility PV Install (2) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 500MW of Utility PV Install (2) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 280MW of Utility PV Install (2) 100MW x 4 hr Energy Storage	Install 280MW of Utility PV Install (2) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		

2045	Install 2320MW of Utility PV	Install 2360MW of Utility PV

Table K-25. Hawaiian Electric Second Iteration Cases (20 of 47)

Case Name	Theme 2, Case 41: Solar, with Storage, HL and ME 100% RE 2040	Theme 2, Case 42: Solar, with Storage, HL and ME 100% RE 2040
Case Label	16_T2bSv1LBf40	16_T2bSv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 20MW of Onshore Wind Install 380MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 7 & 8 Deactivated, 1/2030 Install 1040MW of Utility PV Install (4) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 560MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Install 560MW of Utility PV Install (3) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		

2045	Install 1460MW of Utility PV	Install 1460MW of Utility PV

Table K-26. Hawaiian Electric Second Iteration Cases (21 of 47)

Case Name	Theme 3, Case 43: Solar and Wind	Theme 3, Case 44: Solar and Wind
Case Label	16_T3aWv1L	16_T3aWv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind	Install 670MW of Utility PV Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-27. Hawaiian Electric Second Iteration Cases (22 of 47)

Case Name	Theme 3, Case 45: Solar and Wind	Theme 3, Case 46: Solar and Wind
Case Label	16_T3bWv1L	16_T3bWv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind	Install 1440MW of Utility PV Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-28. Hawaiian Electric Second Iteration Cases (23 of 47)

Case Name	Theme 3, Case 47: Solar	Theme 3, Case 48: Solar
Case Label	16_T3aSv1L	16_T3aSv1H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV	Install 2320MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-29. Hawaiian Electric Second Iteration Cases (24 of 47)

Case Name	Theme 3, Case 49: Solar	Theme 3, Case 50: Solar
Case Label	16_T3bSv1L	16_T3bSv1H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 440MW of Utility PV	Install 20MW of Onshore Wind Install 440MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1370MW of Utility PV	Install 870MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 740MW of Utility PV	Install 1240MW of Utility PV

Table K-30. Hawaiian Electric Second Iteration Cases (25 of 47)

Case Name	Theme 3, Case 51: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 52: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3aWv1L40	16_T3aWv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400 MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind	Install 400 MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 3040 MW of Utility PV

Table K-31. Hawaiian Electric Second Iteration Cases (26 of 47)

Case Name	Theme 3, Case 53: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 54: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3bWv1L40	16_T3bWv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind	Install 1440MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 2000MW of Utility PV

Table K-32. Hawaiian Electric Second Iteration Cases (27 of 47)

Case Name	Theme 3, Case 55: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 56: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3aSv1L40	16_T3aSv1H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV	Install 180 MW of Utility PV
2041		
2042		
2043		
2044		
2045		Install 2360MW of Utility PV

Table K-33. Hawaiian Electric Second Iteration Cases (28 of 47)

Case Name	Theme 3, Case 57: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 58: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3bSv1L40	16_T3bSv1H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 1040MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV	Install 560 MW of Utility PV
2041		
2042		
2043		
2044		
2045		Install 2000MW of Utility PV

Table K-34. Hawaiian Electric Second Iteration Cases (29 of 47)

Case Name	Theme 3, Case 59: Solar and Wind, with Storage	Theme 3, Case 60: Solar and Wind, with Storage
Case Label	16_T3aWv1LBf	16_T3aWv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 2150MW of Utility PV

Table K-35. Hawaiian Electric Second Iteration Cases (30 of 47)

Case Name	Theme 3, Case 61: Solar and Wind, with Storage	Theme 3, Case 62: Solar and Wind, with Storage
Case Label	16_T3bWv1LBf	16_T3bWv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 1620MW of Utility PV

Table K-36. Hawaiian Electric Second Iteration Cases (31 of 47)

Case Name	Theme 3, Case 63: Solar, with Storage	Theme 3, Case 64: Solar, with Storage
Case Label	16_T3aSv1LBf	16_T3aSv1HBf
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 620MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		Install (1) 50 MW x 4 hr Energy Storage
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (2) 100 MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage	Install 2320MW of Utility PV Install (10) 100 MW and (1) 50MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		

Table K-37. Hawaiian Electric Second Iteration Cases (32 of 47)

Case Name	Theme 3, Case 65: Solar, with Storage	Theme 3, Case 66: Solar, with Storage
Case Label	16_T3bSv1LBf	16_T3bSv1HBf
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 440MW of Utility PV	Install 20MW of Onshore Wind Install 440MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV Install (1) 100 MW and (1) 50MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV Install (1) 100 MW and (1) 50MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1370MW of Utility PV Install (5) 100MW x 4 hr Energy Storage	Install 870MW of Utility PV Install (3) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 740MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Install 1240MW of Utility PV Install (5) 100MW x 4 hr Energy Storage

Table K-38. Hawaiian Electric Second Iteration Cases (33 of 47)

Case Name	Theme 3, Case 67: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 68: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3aWv1LBf40	16_T3aWv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028	Install (1) 50 MW x 4 hr Energy Storage	
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind Install (1) 50 MW and (3) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 400 MW of Offshore Wind
2031		
2032		
2033		Install (1) 50MW x 4 hr Energy Storage
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 670MW of Utility PV Install 400MW of Offshore Wind Install (9) 100MW x 4 hr Energy Storage	Install 400 MW of Offshore Wind Install (2) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 2150MW of Utility PV	Install 3040 MW of Utility PV Install (14) 100MW x 4 hr Energy Storage

Table K-39. Hawaiian Electric Second Iteration Cases (34 of 47)

Case Name	Theme 3, Case 69: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 70: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3bWv1LBf40	16_T3bWv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 1440MW of Utility PV Install 400MW of Offshore Wind Install (13) 100MW x 4 hr Energy Storage	Install 1440MW of Utility PV Install (7) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045	Install 1620MW of Utility PV	Install 2000MW of Utility PV Install (6) 100 MW and (1) 50MW x 4 hr Energy Storage

Table K-40. Hawaiian Electric Second Iteration Cases (35 of 47)

Case Name	Theme 3, Case 71: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 72: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3aSv1LBf40	16_T3aSv1HBf40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 620MW of Utility PV	Install 20MW of Onshore Wind Install 400MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (4) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 500MW of Utility PV Install (1) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2320MW of Utility PV Install (21) 100MW x 4 hr Energy Storage	Install 180 MW of Utility PV Install (1) 100MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		Install 2360MW of Utility PV Install (10) 100 MW and (1) 50MW x 4 hr Energy Storage

Table K-41. Hawaiian Electric Second Iteration Cases (36 of 47)

Case Name	Theme 3, Case 73: Solar and Wind, with Storage, HL and ME 100% RE 2040	Theme 3, Case 74: Solar and Wind, with Storage, HL and ME 100% RE 2040
Case Label	16_T3bSv1LBf40	16_T3bSv1HBf40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install 10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 20MW of Onshore Wind Install 380MW of Utility PV	Install 20MW of Onshore Wind Install 380MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 890MW of Utility PV Install (3) 100MW x 4 hr Energy Storage	Waiau 5 & 6 Deactivated, 1/2030 Install 1040MW of Utility PV Install (2) 100MW x 4 hr Energy Storage
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 2110MW of Utility PV Install (10) 100MW x 4 hr Energy Storage	Install 560 MW of Utility PV Install (1) 100 MW and (1) 50MW x 4 hr Energy Storage
2041		
2042		
2043		
2044		
2045		Install 2000MW of Utility PV Install (6) 100MW x 4 hr Energy Storage

Table K-42. Hawaiian Electric Second Iteration Cases (37 of 47)

Case Name	Theme 2, Case 75: Solar and Wind	Theme 2, Case 76: Solar and Wind
Case Label	16_T2aWv2L40	16_T2aWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-43. Hawaiian Electric Second Iteration Cases (38 of 47)

Case Name	Theme 2, Case 77: Solar and Wind	Theme 2, Case 78: Solar and Wind
Case Label	16_T2bWv2L40	16_T2bWv2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-44. Hawaiian Electric Second Iteration Cases (39 of 47)

Case Name	Theme 2, Case 79: Solar and Wind, Accelerated Build Out	Theme 2, Case 80: Solar and Wind, Accelerated Build Out
Case Label	16_T2aW25v2L40	16_T2aW25v2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind

Table K-45. Hawaiian Electric Second Iteration Cases (40 of 47)

Case Name	Theme 2, Case 81: Solar and Wind, Accelerated Build Out	Theme 2, Case 82: Solar and Wind, Accelerated Build Out
Case Label	16_T2bW25v2L40	16_T2bW25v2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030	Waiau 7 & 8 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-46. Hawaiian Electric Second Iteration Cases (41 of 47)

Case Name	Theme 2, Case 83: Solar and Wind, Static Utility Build Out	Theme 2, Case 84: Solar and Wind, Static Utility Build Out
Case Label	16_T2abWv2L40	16_T2abWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-47. Hawaiian Electric Second Iteration Cases (42 of 47)

Case Name	Theme 3, Case 85: Solar and Wind	Theme 3, Case 86: Solar and Wind
Case Label	16_T3aWv2L40	16_T3aWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 420MW of Utility PV Install 800MW of Offshore Wind	Install 420MW of Utility PV Install 800MW of Offshore Wind

Table K-48. Hawaiian Electric Second Iteration Cases (43 of 47)

Case Name	Theme 3, Case 87: Solar and Wind	Theme 3, Case 88: Solar and Wind
Case Label	16_T3bWv2L40	16_T3bWv2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 160MW of Utility PV Install 800MW of Offshore Wind	Install 160MW of Utility PV Install 800MW of Offshore Wind

Table K-49. Hawaiian Electric Second Iteration Cases (44 of 47)

Case Name	Theme 3, Case 89: Solar and Wind, Accelerated Build Out	Theme 3, Case 90: Solar and Wind, Accelerated Build Out
Case Label	16_T3aW25v2L40	16_T3aW25v2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 420MW of Utility PV Install 800MW of Offshore Wind	Install 420MW of Utility PV Install 800MW of Offshore Wind

Table K-50. Hawaiian Electric Second Iteration Cases (45 of 47)

Case Name	Theme 3, Case 91: Solar and Wind, Accelerated Build Out	Theme 3, Case 92: Solar and Wind, Accelerated Build Out
Case Label	16_T3bW25v2L40	16_T3bW25v2H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind	Kahe 6 Deactivated, 1/2025 Install 400MW of Offshore Wind
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 160MW of Utility PV Install 800MW of Offshore Wind	Install 160MW of Utility PV Install 800MW of Offshore Wind

Table K-51. Hawaiian Electric Second Iteration Cases (46 of 47)

Case Name	Theme 3, Case 93: Solar and Wind, Static Utility Build Out	Theme 3, Case 94: Solar and Wind, Static Utility Build Out
Case Label	16_T3abWv2L40	16_T3abWv2H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 160MW of Utility PV Install 800MW of Offshore Wind	Install 160MW of Utility PV Install 800MW of Offshore Wind

Table K-52. Hawaiian Electric Second Iteration Cases (47 of 47)

Hawaiian Electric Third Iteration Cases

Case Name	Theme 2, Case 95: Solar and Wind	Theme 2, Case 96: Solar and Wind
Case Label	16_T2aWv3L	16_T2aWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind	Install 1200 MW of Offshore Wind

Table K-53. Hawaiian Electric Third Iteration Cases (1 of 31)

Case Name	Theme 3, Case 97: Solar and Wind	Theme 3, Case 98: Solar and Wind
Case Label	16_T2bWv3L	16_T2bWv3H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-54. Hawaiian Electric Third Iteration Cases (2 of 31)

Case Name	Theme 2, Case 99: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 100: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2aWv3L40	16_T2aWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 320 MW of Utility PV	Install 1200 MW of Offshore Wind Install 320 MW of Utility PV

Table K-55. Hawaiian Electric Third Iteration Cases (3 of 31)

Case Name	Theme 2, Case 101: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 102: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T2bWv3L40	16_T2bWv3H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 140MW of Utility PV	Install 1200MW of Offshore Wind Install 140MW of Utility PV

Table K-56. Hawaiian Electric Third Iteration Cases (4 of 31)

Case Name	Theme 2, Case 103: Solar and Wind, DG PV Regulation	Theme 2, Case 104: Solar and Wind, DG PV Regulation
Case Label	16_T2aWv3Hhc	16_T2bWv3Hhc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-57. Hawaiian Electric Third Iteration Cases (5 of 31)

Case Name	Theme 2, Case 105: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040	Theme 2, Case 106: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040
Case Label	16_T2aWv3H40hc	16_T2bWv3H40hc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 320 MW of Utility PV	Install 1200MW of Offshore Wind Install 140MW of Utility PV

Table K-58. Hawaiian Electric Third Iteration Cases (6 of 31)

Case Name	Theme 2, Case 107: Solar and Wind, Static Utility Build Out	Theme 2, Case 108: Solar and Wind, Static Utility Build Out
Case Label	16_T2abWv3L	16_T2abWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 520MW of Utility PV	Install 520MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind	Install 1200MW of Offshore Wind

Table K-59. Hawaiian Electric Third Iteration Cases (7 of 31)

Case Name	Theme 2, Case 109: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040	Theme 2, Case 110: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040
Case Label	16_T2abWv3L40	16_T2abWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 140MW of Utility PV	Install 1200MW of Offshore Wind Install 140MW of Utility PV

Table K-60. Hawaiian Electric Third Iteration Cases (8 of 31)

Case Name	Theme 2, Case 111: Solar and Wind, Utility Storage	Theme 2, Case 112: Solar and Wind, Utility Storage, HL and ME 100% RE 2040
Case Label	16_T2aWv3LBp	16_T2aWv3LBp40
DER Forecast	High	High
Fuel Price	Low	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 550 MW of 8-hour batteries	Install 1200 MW of Offshore Wind Install 500 MW of 8-hour batteries

Table K-61. Hawaiian Electric Third Iteration Cases (9 of 31)

Case Name	Theme 2, Case 113: Solar and Wind, Circuit Level Storage	Theme 2, Case 114: Solar and Wind, Circuit Level Storage, HL and ME 100% RE 2040
Case Label	16_T2aWv3LCBf	16_T2aWv3LCBf40
DER Forecast	High w/circuit battery	High w/circuit battery
Fuel Price	Low	Low
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 20MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 500MW of Utility PV	Install 500MW of Utility PV
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 250 MW of 8-hour batteries	Install 1200 MW of Offshore Wind Install 200 MW of 8-hour batteries

Table K-62. Hawaiian Electric Third Iteration Cases (10 of 31)

Case Name	Theme 3, Case 115: Solar and Wind	Theme 3, Case 116: Solar and Wind
Case Label	16_T3aWv3L	16_T3aWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800 MW of Offshore Wind Install 420 MW of Utility PV	Install 800 MW of Offshore Wind Install 420 MW of Utility PV

Table K-63. Hawaiian Electric Third Iteration Cases (11 of 31)

Case Name	Theme 3, Case 117: Solar and Wind	Theme 3, Case 118: Solar and Wind
Case Label	16_T3bWv3L	16_T3bWv3H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800MW of Offshore Wind Install 160 MW of Utility PV	Install 800MW of Offshore Wind Install 160 MW of Utility PV

Table K-64. Hawaiian Electric Third Iteration Cases (12 of 31)

Case Name	Theme 3, Case 119: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 120: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3aWv3L40	16_T3aWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 420 MW of Utility PV	Install 1200 MW of Offshore Wind Install 420 MW of Utility PV

Table K-65. Hawaiian Electric Third Iteration Cases (13 of 31)

Case Name	Theme 3, Case 121: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 122: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_T3bWv3L40	16_T3bWv3H40
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 160 MW of Utility PV	Install 1200MW of Offshore Wind Install 160 MW of Utility PV

Table K-66. Hawaiian Electric Third Iteration Cases (14 of 31)

Case Name	Theme 3, Case 123: Solar and Wind, DG PV Regulation	Theme 3, Case 124: Solar and Wind, DG PV Regulation
Case Label	16_T3aWv3Hhc	16_T3bWv3Hhc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800 MW of Offshore Wind Install 420 MW of Utility PV	Install 800MW of Offshore Wind Install 160 MW of Utility PV

Table K-67. Hawaiian Electric Third Iteration Cases (15 of 31)

Case Name	Theme 3, Case 125: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040	Theme 3, Case 126: Solar and Wind, DG PV Regulation, HL and ME 100% RE 2040
Case Label	16_T3aWv3H40hc	16_T3bWv3H40hc
DER Forecast	High minus 10%	Market minus 10%
Fuel Price	High	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1200 MW of Offshore Wind Install 420 MW of Utility PV	Install 1200MW of Offshore Wind Install 160 MW of Utility PV

Table K-68. Hawaiian Electric Third Iteration Cases (16 of 31)

Case Name	Theme 3, Case 127: Solar and Wind, Static Utility Build Out	Theme 3, Case 128: Solar and Wind, Static Utility Build Out
Case Label	16_T3abWv3L	16_T3abWv3H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 800MW of Offshore Wind	Install 800MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 800MW of Offshore Wind Install 160 MW of Utility PV	Install 800MW of Offshore Wind Install 160 MW of Utility PV

Table K-69. Hawaiian Electric Third Iteration Cases (17 of 31)

Case Name	Theme 3, Case 129: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040	Theme 3, Case 130: Solar and Wind, Static Utility Build Out, HL and ME 100% RE 2040
Case Label	16_T3abWv3L40	16_T3baWv3H40
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind	Install 30MW of Onshore Wind
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 40MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 1200MW of Offshore Wind Install 160 MW of Utility PV	Install 1200MW of Offshore Wind Install 160 MW of Utility PV

Table K-70. Hawaiian Electric Third Iteration Cases (18 of 31)

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Case Name	Theme 1, Case 131: Solar and Wind, HL and ME 100% RE 2030	Theme 1, Case 132: Solar and Wind, HL and ME 100% RE 2030
Case Label	16_T1aWL30v6	16_T1aWH30v6
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW Onshore Wind Install 200MW of Utility PV	Install 30MW Onshore Wind Install 200MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024	Install 220 MW of Utility PV	Install 220 MW of Utility PV
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200 MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2033		
2034	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2035		
2036	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-71. Hawaiian Electric Third Iteration Cases (19 of 31)

Case Name	Theme 2, Case 133: Wind, HL and ME 100% RE 2040	Theme 2, Case 134: Wind, HL and ME 100% RE 2040
Case Label	16_PT2aWv4L	16_PT2aWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-72. Hawaiian Electric Third Iteration Cases (20 of 31)

Case Name	Theme 2, Case 135: Wind, HL and ME 100% RE 2040	Theme 2, Case 136: Wind, HL and ME 100% RE 2040
Case Label	16_PT2bWv4L	16_PT2bWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-73. Hawaiian Electric Third Iteration Cases (21 of 31)

Case Name	Theme 2, Case 137: Solar, HL and ME 100% RE 2040	Theme 2, Case 138: Solar, HL and ME 100% RE 2040
Case Label	16_PT2aSv4L	16_PT2aSv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-74. Hawaiian Electric Third Iteration Cases (22 of 31)

Case Name	Theme 2, Case 139: Solar, HL and ME 100% RE 2040	Theme 2, Case 140: Solar, HL and ME 100% RE 2040
Case Label	16_PT2bSv4L	16_PT2bSv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 7 & 8 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-75. Hawaiian Electric Third Iteration Cases (23 of 31)

Case Name	Theme 2, Case 141: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 142: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT2aSWv4L	16_PT2aSWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		

2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-76. Hawaiian Electric Third Iteration Cases (24 of 31)

Case Name	Theme 2, Case 143: Solar and Wind, HL and ME 100% RE 2040	Theme 2, Case 144: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT2bSWv4L	16_PT2bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		

2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-77. Hawaiian Electric Third Iteration Cases (25 of 31)

Case Name	Theme 3, Case 145: Wind, HL and ME 100% RE 2040	Theme 3, Case 146: Wind, HL and ME 100% RE 2040
Case Label	16_PT3aWv4L	16_PT3aWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-78. Hawaiian Electric Third Iteration Cases (26 of 31)

Case Name	Theme 3, Case 147: Wind, HL and ME 100% RE 2040	Theme 3, Case 148: Wind, HL and ME 100% RE 2040
Case Label	16_PT3bWv4L	16_PT3bWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Offshore Wind	Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 400MW of Offshore Wind	Install 400MW of Offshore Wind

Table K-79. Hawaiian Electric Third Iteration Cases (27 of 31)

Case Name	Theme 3, Case 149: Solar, HL and ME 100% RE 2040	Theme 3, Case 150: Solar, HL and ME 100% RE 2040
Case Label	16_PT3aSv4L	16_PT3aSv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-80. Hawaiian Electric Third Iteration Cases (28 of 31)

Case Name	Theme 3, Case 151: Solar, HL and ME 100% RE 2040	Theme 3, Case 152: Solar, HL and ME 100% RE 2040
Case Label	16_PT3bSv4L	16_PT3bSv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV	Waiau 5 & 6 Deactivated, 1/2030 Install 400MW of Utility PV
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV	Install 200MW of Utility PV
2041		
2042		
2043		
2044		
2045		

Table K-81. Hawaiian Electric Third Iteration Cases (29 of 31)

Case Name	Theme 3, Case 153: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 154: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT3aSWv4L	16_PT3aSWv4H
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-82. Hawaiian Electric Third Iteration Cases (30 of 31)

Case Name	Theme 3, Case 155: Solar and Wind, HL and ME 100% RE 2040	Theme 3, Case 156: Solar and Wind, HL and ME 100% RE 2040
Case Label	16_PT3bSWv4L	16_PT3bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added	90 MW Contingency BESS added
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023
2024		
2025	Kahe 6 Deactivated, 1/2025	Kahe 6 Deactivated, 1/2025
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		
2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-83. Hawaiian Electric Third Iteration Cases (31 of 31)

Hawaiian Electric Final Plans

Case Name	Final Plan, Theme 1 (Case 131)	Final Plan, Theme 1 (Case 132)
Case Label	16_T1aWL30v6	16_T1aWH30v6
DER Forecast	High	High
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser
2020	Install 30MW Onshore Wind Install 200MW of Utility PV	Install 30MW Onshore Wind Install 200MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022 Install 200MW of Utility PV
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser
2024	Install 220 MW of Utility PV	Install 220 MW of Utility PV
2025	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 200 MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 200MW of Offshore Wind
2031		
2032	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2033		
2034	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2035		
2036	Install 200 MW of Offshore Wind	Install 200 MW of Offshore Wind
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-84. Hawaiian Electric Final Cases (1 of 3)

Case Name	Final Plan, Theme 2 (Case 143)	Final Plan, Theme 2 (Case 144)
Case Label	16_PT2bSWv4L	16_PT2bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser
2020	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 100MW JBPHH Plant, 12/2020 Kahe 1, 2, 3 Deactivated, 12/2020 Install 30MW of Onshore Wind Install 60MW of Utility PV
2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021	Install 27 MW KMCBH Plant, 6/2021 Install 3x1 CC, 6/2021
2022	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 Kahe 1, 2, 3 converted to synchronous condenser	AES Deactivated 9/2022 Waiau 3 & 4 Deactivated, 1/2022 Kahe 4 Deactivated, 1/2022 Kahe 1, 2, 3 converted to synchronous condenser
2023		
2024	Waiau 5 & 6 Deactivated, 1/2024	Waiau 5 & 6 Deactivated, 1/2024
2025		
2026		
2027		
2028		
2029		
2030	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind	Waiau 7 & 8 Deactivated, 1/2030 Install 100MW of Utility PV Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		

2044		
2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-85. Hawaiian Electric Final Cases (2 of 3)

Case Name	Final Plan, Theme 3 (Case 155)	Final Plan, Theme 3 (Case 156)
Case Label	16_PT3bSWv4L	16_PT3bSWv4H
DER Forecast	Market	Market
Fuel Price	Low	High
2016	27.6 MW Waiver PV Projects added 12/31/2016	27.6 MW Waiver PV Projects added 12/31/2016
2017		
2018	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)	Six -8.14 MW Schofield Plants added Install 24MW NPM Wind 109.6MW Waiver PV added 1/1/2018 Install10MW of Onshore Wind (CBRE) Install 15MW of Utility PV (CBRE)
2019	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser	90 MW Contingency BESS added Convert H8 & 9 to synchronous condenser
2020	Install 30MW of Onshore Wind Install 60MW of Utility PV	Install 30MW of Onshore Wind Install 60MW of Utility PV
2021		
2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022	Install 100MW JBPHH Plant, 1/2022 AES Deactivated 9/2022
2023	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser	Install 54MW KMBCH Plant, 1/2023 Waiau 3 & 4 Deactivated, 1/2023 Waiau 3 & 4 converted to synchronous condenser
2024		
2025	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser	Kahe 6 Deactivated, 1/2025 Kahe 6 converted to synchronous condenser
2026		
2027		
2028		
2029		
2030	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility-scale Solar Install 200MW of Offshore Wind	Waiau 5 & 6 Deactivated, 1/2030 Install 100MW of Utility-scale Solar Install 200MW of Offshore Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 200MW of Utility PV Install 200MW of Offshore Wind	Install 200MW of Utility PV Install 200MW of Offshore Wind
2041		
2042		
2043		
2044		

2045	Install 300MW of Utility PV Install 400MW of Offshore Wind	Install 300MW of Utility PV Install 400MW of Offshore Wind

Table K-86. Hawaiian Electric Final Cases (3 of 3)

HAWAI'I ELECTRIC LIGHT

Hawai'i Electric Light First Iteration, PSIP Interim: 100% RE in 2045 with LNG.

Case Name	Interim: 100% Renewable in 2045, with LNG	Interim: 100% Renewable in 2045, with LNG
Case Label	33	35
DER Forecast	Preliminary Market	Preliminary Market
Fuel Price	2015 EIA Reference	April 2015 Low
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025	Install 25 MW Geo Puna Steam Deactivated	Install 25 MW Geo Puna Steam Deactivated
2026		
2027		
2028		
2029	Install 21 MW Biomass Hill 5 Deactivated	Install 21 MW Biomass Hill 5 Deactivated
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039	Naptha & ULSD to biofuel	Naptha & ULSD to biofuel
2040	Diesel to biofuel	Diesel to biofuel
2041		
2042		
2043		
2044		
2045	IFO to biofuel	IFO to biofuel

Table K-87. Hawai'i Electric Light Cases (1 of 15)

First Iteration, PSIP Interim: 100% RE in 2045 without LNG.

Case Name	Interim: 100% Renewable in 2045, without LNG	Interim: 100% Renewable in 2045, without LNG
Case Label	34a	36a
DER Forecast	Preliminary Market	Preliminary Market
Fuel Price	2015 EIA Reference	2016 Forward/Hybrid Curve
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025	Install 25 MW Geo Puna Steam Deactivated	Install 25 MW Geo Puna Steam Deactivated
2026		
2027		
2028		
2029	Install 21 MW Biomass Hill 5 Deactivated	Install 21 MW Biomass Hill 5 Deactivated
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		Naptha to biofuel
2039	Naptha & ULSD to biofuel	ULSD to biofuel
2040	Diesel to biofuel	Diesel to biofuel
2041		
2042		
2043		
2044		
2045	IFO to biofuel	IFO to biofuel

Table K-88. Hawai'i Electric Light Cases (2 of 15)

Second Iteration, Theme 1: Aggressive 100% RE with minimal biofuels.

Case Name	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions
Case Label	40g3	40s
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024	Install 20 MW Biomass Hill 5 Deactivated	Install20 MW Biomass Hill 5 Deactivated
2025		
2026	Install 20 MW Geo Hill 6 deactivated	Install20 MW Geo Hill 6 deactivated
2027		
2028	Install 30 MW Wind	Install 30 MW Wind
2029		
2030	Install 30MW/6hr LS BESS x 2 Biofuel	Install 30MW/6hr LS BESS x 2 Biofuel
2031		
2032		
2033		
2034		
2035	Install 30MW/6hr LS BESS	Install 30MW/6hr LS BESS
2036		
2037		
2038		
2039		
2040	Install 30MW/6hr LS BESS	Install 30MW/6hr LS BESS
2041		
2042		
2043		
2044		
2045	Install 30MW/6hr LS BESS	Install 30MW/6hr LS BESS

Table K-89. Hawai'i Electric Light Cases (3 of 15)

Second Iteration, Theme 1: Aggressive 100% RE with minimal biofuels.

Case Name	Theme 1: 100% Renewable in 2030, without Firm RE Additions; Wind & PV Only	Theme 1: 100% Renewable in 2030, without Firm RE Additions; Wind & PV Only
Case Label	40o4	40t
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	Install 30 MW Wind	Install 30 MW Wind
2021		
2022	Install 30 MW Wind	Install 30 MW Wind
2023	Install 30 MW Pumped storage hydro	Install 30 MW Pumped storage hydro
2024	Install 30 MW Wind	Install 30 MW Wind
2025		
2026	Install 30 MW Wind	Install 30 MW Wind
2027		
2028	Install 30 MW Wind	Install 30 MW Wind
2029		
2030	Install 210 MW Wind Install 720 MWH storage (30MW/6hr LS BESS, 4 ea) Biofuel	Install 210 MW Wind Install 720 MWH storage (30MW/6hr LS BESS, 4 ea) Biofuel
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 30 MW Wind	Install 30 MW Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Wind	Install 30 MW Wind

Table K-90. Hawai'i Electric Light Cases (4 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, High DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2040 with LNG	Theme 2: 100% Renewable in 2040 with LNG
Case Label	39a	39g
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		Install 20 MW Geo Hill 6 deactivated
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-91. Hawai'i Electric Light Cases (5 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, Market DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2040 with LNG	Theme 2: 100% Renewable in 2040 with LNG
Case Label	39f	39b
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		Install 20 MW Geo Hill 6 deactivated
2033		
2034	Install 20 MW Wind	
2035		
2036		
2037		Install 20 MW Wind
2038	Install 20 MW Wind	
2039		
2040	Biofuel	Install 20 MW Wind Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-92. Hawai'i Electric Light Cases (6 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, High DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2045 with LNG	Theme 2: 100% Renewable in 2045 with LNG
Case Label	39c	39i
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		
2033		
2034		
2035		Install 20 MW Geo Hill 6 deactivated
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Biofuel	Biofuel

Table K-93. Hawai'i Electric Light Cases (7 of 15)

Second Iteration, Theme 2: Path to 100% RE with LNG, Market DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2045 with LNG	Theme 2: 100% Renewable in 2045 with LNG
Case Label	39h	39d
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021	LNG CC Units	LNG CC Units
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030	Install 20 MW Geo Hill 6 deactivated	
2031		
2032		Install 20 MW Geo Hill 6 deactivated
2033		
2034	Install 20 MW Wind	
2035		
2036		
2037		Install 20 MW Wind
2038	Install 20 MW Wind	
2039		
2040		
2041		Install 20 MW Wind
2042	Install 20 MW Wind	
2043		
2044		
2045	Biofuel	Biofuel

Table K-94. Hawai'i Electric Light Cases (8 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, high DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2040 without LNG	Theme 3: 100% Renewable in 2040 without LNG
Case Label	42s	42q
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		
2035		Install 20 MW Geo Hill 6 deactivated
2036		
2037		
2038		
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-95. Hawai'i Electric Light Cases (9 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, Market DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2040 without LNG	Theme 3: 100% Renewable in 2040 without LNG
Case Label	42r	42p
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		Install 20 MW Geo Hill 6 deactivated
2035	Install 20 MW Wind	
2036		
2037		Install 20 MW Wind
2038		
2039		
2040	Install 20 MW Wind Biofuel	Install 20 MW Wind Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-96. Hawai'i Electric Light Cases (10 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, high DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2045 without LNG	Theme 3: 100% Renewable in 2045 without LNG
Case Label	42o	42k
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		
2035		Install 20 MW Geo Hill 6 deactivated
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	Biofuel	Biofuel

Table K-97. Hawai'i Electric Light Cases (11 of 15)

Second Iteration, Theme 3: Path to 100% RE without LNG, Market DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2045 without LNG	Theme 3: 100% Renewable in 2045 without LNG
Case Label	42n	42h
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	
2028		Install 20 MW Biomass Hill 5 Deactivated
2029		
2030		
2031		
2032		
2033	Install 20 MW Geo Hill 6 deactivated	
2034		
2035	Install 20 MW Wind	Install 20 MW Geo Hill 6 deactivated
2036		
2037		Install 20 MW Wind
2038		
2039		
2040	Install 20 MW Wind	
2041		
2042		Install 20 MW Wind
2043		
2044		
2045	Biofuel	Biofuel

Table K-98. Hawai'i Electric Light Cases (12 of 15)

Third Iteration, Theme 1: Aggressive 100% RE with minimal biofuels.

Case Name	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions	Theme 1: 100% Renewable in 2030,with Firm Renewable Additions
Case Label	50w4	50x2
DER Forecast	High	High
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024	Install 20 MW Biomass Hill 5 Deactivated	Install20 MW Biomass Hill 5 Deactivated
2025		
2026	Install 20 MW Geo Hill 6 deactivated	Install20 MW Geo Hill 6 deactivated
2027		
2028	Install 30 MW Wind	Install 30 MW Wind
2029		
2030	Install 30MW/6hr LS BESS, Install 30 MW Pumped Storage Hydro, Biofuel	Install 30MW/6hr LS BESS, Install 30 MW Pumped Storage Hydro, Biofuel
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-99. Hawai'i Electric Light Cases (13 of 15)

Third Iteration, Theme 2: Path to 100% RE with LNG, Market DG PV forecast.

Case Name	Theme 2: 100% Renewable in 2040 with LNG	Theme 2: 100% Renewable in 2040 with LNG
Case Label	49f1	49f1_lowfuel
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	Install 20 MW Biomass Hill 5 Deactivated
2028		
2029		
2030	Install 20 MW Geo Hill 6 deactivated	Install 20 MW Geo Hill 6 deactivated
2031		
2032		
2033		
2034	Install 20 MW Wind	Install 20 MW Wind
2035		
2036		
2037		
2038	Install 20 MW Wind	Install 20 MW Wind
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-100. Hawai'i Electric Light Cases (14 of 15)

Third Iteration, Theme 3: Path to 100% RE without LNG, Market DG PV forecast.

Case Name	Theme 3: 100% Renewable in 2040 without LNG	Theme 3: 100% Renewable in 2040 without LNG
Case Label	52t	52u
DER Forecast	Market	Market
Fuel Price	2015 EIA Reference	February 2016 EIA STEO
2016		
2017		
2018		
2019		
2020		
2021		
2022	Install 20 MW Geo Puna Steam Deactivated	Install 20 MW Geo Puna Steam Deactivated
2023		
2024		
2025		
2026		
2027	Install 20 MW Biomass Hill 5 Deactivated	Install 20 MW Biomass Hill 5 Deactivated
2028		
2029		
2030	Install 20 MW Geo Hill 6 deactivated	Install 20 MW Geo Hill 6 deactivated
2031		
2032		
2033		
2034	Install 20 MW Wind	Install 20 MW Wind
2035		
2036		
2037		
2038	Install 20 MW Wind	Install 20 MW Wind
2039		
2040	Biofuel	Biofuel
2041		
2042		
2043		
2044		
2045		

Table K-101. Hawai'i Electric Light Cases (15 of 15)

MAUI ELECTRIC

Theme 1 Cases

DG-PV Forecast	Fuel Forecast	Primary RE Type	Biofuel	Plan	Case
High DG-PV	2015 EIA Reference	Non-Firm	Biofuel & BESS		33
	2015 EIA Reference	Firm	Biofuel & BESS	Final	34
	Feb 2016 EIA STEO	Non-Firm	Biofuel & BESS		35
	Feb 2016 EIA STEO	Firm	Bio		36
	Feb 2016 EIA STEO	Firm	No BESS		45
	Feb 2016 EIA STEO	Firm	Biofuel & BESS		46
	Feb 2016 EIA STEO	Firm	Biofuel & BESS	Sensitivity on Final	55

Table K-102. Maui Theme 1 Cases

Theme 2 Cases

DG-PV Forecast	Fuel Forecast	100% RE Target	Plan	Case
Interim	Interim High	100% RE 2045	Interim	8
	Interim Low	100% RE 2045	Interim	10
High DG-PV	2015 EIA Reference	100% RE 2045		29
	2015 EIA Reference	100% RE 2040		42
	Feb 2016 EIA STEO	100% RE 2045		30
	Feb 2016 EIA STEO	100% RE 2040		41
Market DG-PV	2015 EIA Reference	100% RE 2045		24
	2015 EIA Reference	100% RE 2040		38
	2015 EIA Reference	100% RE 2040	Final	52
	Feb 2016 EIA STEO	100% RE 2045		23
	Feb 2016 EIA STEO	100% RE 2040		37
	Feb 2016 EIA STEO	100% RE 2040	Sensitivity on Final	62

Table K-103. Maui Theme 2 Cases

Theme 3 Cases

DG-PV Forecast	Fuel Forecast	100% RE Target	Plan	Case
Interim	Interim High	100% RE 2045	Interim	9
	Interim Low	100% RE 2045	Interim	11
High DG-PV	2015 EIA Reference	100% RE 2045		31
	2015 EIA Reference	100% RE 2040		44
	Feb 2016 EIA STEO	100% RE 2045		32
	Feb 2016 EIA STEO	100% RE 2040		43
Market DG-PV	2015 EIA Reference	100% RE 2045		26
	2015 EIA Reference	100% RE 2040		40
	2015 EIA Reference	100% RE 2040	Final	54
	Feb 2016 EIA STEO	100% RE 2045		25
	Feb 2016 EIA STEO	100% RE 2040		39
	Feb 2016 EIA STEO	100% RE 2040	Sensitivity on Final	53

Table K-104. Maui Theme 3 Cases

PSIP Interim Filing Cases 8 & 9: High Fuel Forecast

Case Name	Case 8	Case 9
Case Label	ICE & Geo	ICE & Geo without LNG
DER Forecast	Interim	Interim
Fuel Price	Interim High	Interim High
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020		
2021		
2022	Install Eight - 9 MW ICE	Install Eight - 9 MW ICE
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 20 MW Geothermal	Install 20 MW Geothermal
2036		
2037		
2038		
2039	Install Two - 5 MW 4 hr BESS for Capacity	Install Two - 5 MW 4 hr BESS for Capacity
2040		
2041	Install 20 MW Geothermal	Install 20 MW Geothermal
2042		
2043		
2044		
2045		

Table K-105. Maui PSIP Interim Filing Cases 8 & 9: Interim High Fuel Forecast

PSIP Interim Filing Cases 10 & 11: Low Fuel Forecast

Case Name	Case 10	Case 11
Case Label	ICE & Geo Low Fuel	ICE & Geo Low Fuel without LNG
DER Forecast	Interim	Interim
Fuel Price	Interim Low	Interim Low
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020		
2021		
2022	Install Eight - 9 MW ICE	Install Eight - 9 MW ICE
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 20 MW Geothermal	Install 20 MW Geothermal
2036		
2037		
2038		
2039	Install Two - 5 MW 4 hr BESS for Capacity	Install Two - 10 MW 4 hr BESS for Capacity
2040		
2041	Install 20 MW Geothermal	Install 20 MW Geothermal
2042		
2043		
2044		
2045		

Table K-106. Maui PSIP Interim Filing Cases 10 & 11: Interim Low Fuel Forecast

Maui PSIP Cases 23 & 24

Case Name	Case 23	Case 24
Case Label	MLB45	MHB45
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Four - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	

Table K-107. Maui PSIP Cases 23 & 24

Maui PSIP Cases 25 & 26

Case Name	Case 25	Case 26
Case Label	ULB45	UHB45
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-108. Maui PSIP Cases 25 & 26

Maui PSIP Cases 29 & 30

Case Name	Case 29	Case 30
Case Label	MHH45	MLH45
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		Install 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass
2041		
2042		
2043		
2044		
2045	Install Three - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Four - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-109. Maui PSIP Cases 29 & 30

Maui PSIP Cases 31 & 32

Case Name	Case 31	Case 32
Case Label	UHH45	ULH45
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Two - 20 MW Future PV	Install 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-110. Maui PSIP Cases 31 & 32

Maui PSIP Cases 33 & 34

Case Name	Case 33	Case 34
Case Label	THH30AABioBESS	THH30BioBESS
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Five - 30 MW Future Wind, Install Two - 20 MW Biomass, Install 30 MW 6 hr BESS for Load Shifting	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-111. Maui PSIP Cases 33 & 34

Maui PSIP Cases 35 & 36

Case Name	Case 35	Case 36
Case Label	TLH30AABioBESS	TLH30
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Five - 30 MW Future Wind, Install Two - 20 MW Biomass, Install 30 MW 6 hr BESS for Load Shifting	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass, Install Sixteen - 30 MW 6 hr BESS for Load Shifting
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	Install Four - 30 MW 6 hr BESS for Load Shifting
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind, Install Four - 30 MW 6 hr BESS for Load Shifting
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Two - 30 MW Future Wind, Install Twelve - 30 MW 6 hr BESS for Load Shifting

Table K-112. Maui PSIP Cases 35 & 36

Maui PSIP Cases 37 & 38

Case Name	Case37	Case 38
Case Label	MLB40	MHB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023	Convert K2 & K4 to Synchronous Condensers	Convert K2 & K4 to Synchronous Condensers
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Install 30 MW 6 hr BESS for Capacity	Install 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Four - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Four -30 MW Future Wind, Install Three - 20 MW Future PV Install Three - 20 MW 1 hr BESS for Regulation

Table K-113. Maui PSIP Cases 37 & 38

Maui PSIP Cases 39 & 40

Case Name	Case 39	Case 40
Case Label	ULB40	UHB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037		Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Two - 30 MW Future Wind	Install 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-114. Maui PSIP Cases 39 & 40

Maui PSIP Cases 41 & 42

Case Name	Case 41	Case 42
Case Label	MLH40	MHH40
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Install 30 MW 6 hr BESS for Capacity	Install 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install 30 MW Future Wind	Install 20 MW Biomass
2041		
2042		
2043		
2044		
2045	Install Three - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install Three - 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-115. Maui PSIP Cases 41 & 42

Maui PSIP Cases 43 & 44

Case Name	Case 43	Case 44
Case Label	ULH40	UHH40
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035	Install 30 MW Future Wind	
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	
2038		
2039		
2040	Install 20 MW Biomass	Install 20 MW Biomass, Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind	Install 30 MW Future Wind, Install Three - 20 MW Future PV

Table K-116. Maui PSIP Cases 43 & 44

Maui PSIP Cases 45 & 46

Case Name	Case 45	Case 46
Case Label	TLH30Bio	TLH30BioBESS
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass, Install Two - 30 MW 6 hr BESS for Load Shifting
2031		
2032		
2033		
2034		
2035		Install 30 MW 6 hr BESS for Load Shifting
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install Two - 30 MW Future Wind, Install 20 MW 1 hr BESS for Regulation	Install Two - 30 MW Future Wind

Table K-117. Maui PSIP Cases 45 & 46

Maui PSIP Final Theme 1 Cases 34 & 55

Case Name	Case 34	Case 55
Case Label	THH30BioBESS	TLH30BioBESS
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install 30 MW Future Wind	Install 30 MW Future Wind
2021		
2022	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)	Install 30 MW Pumped Storage Hydro, Install 20 MW Biomass, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)
2023	Convert K1, K2, K3, K4 to Synchronous Condensers	Convert K1, K2, K3, K4 to Synchronous Condensers
2024		
2025		
2026		
2027		
2028		
2029		
2030	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass	Install Two - 20 MW Geothermal, Install Two - 20 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	Install 30 MW Future Wind	Install 30 MW Future Wind
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation	Install 30 MW Future Wind, Install Three - 20 MW 1 hr BESS for Regulation

Table K-118. Maui PSIP Final Theme 1 Cases 34 & 55

Maui PSIP Final Theme 2 Cases 52 & 62

Case Name	Case 52	Case 62
Case Label	MHB40	MLB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)	Install Two - 9 MW ICE, Install 20 MW Biomass, 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)
2023	Convert K1, K2, K3, K4 to Synchronous Condensers	Convert K1, K2, K3, K4 to Synchronous Condensers
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Four - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Four - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Two - 20 MW Future PV	Install 30 MW Future Wind, Install Two - 20 MW Future PV

Table K-119. Maui PSIP Final Theme 2 Cases 52 & 62

Maui PSIP Final Theme 2 Cases 54 & 53

Case Name	Case 54	Case 53
Case Label	UHB40	ULB40
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017	5.74 MW of PV Projects	5.74 MW of PV Projects
2018		
2019		
2020	Install Two - 30 MW Future Wind	Install Two - 30 MW Future Wind
2021		
2022	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)	Install Two - 9 MW ICE, Install 20 MW Biomass, Install 30 MW Future Wind, Install 20 MW 4 hr BESS for Capacity, Install 20 MW 1hr BESS for South Maui Non-Transmission Alternative Install two - 30 MW Synchronous Condenser (Maalaea)
2023	Convert K1, K2, K3, K4 to Synchronous Condensers	Convert K1, K2, K3, K4 to Synchronous Condensers
2024		
2025	Install 30 MW Future Wind	Install 30 MW Future Wind
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity	Renew 20 MW 4hr BESS with a 30 MW 6 hr BESS for Capacity
2038		
2039		
2040	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Two - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation	Install 20 MW Biomass, Install Two - 20 MW Geothermal, Install Two - 30 MW Future Wind Install Two - 20 MW 1hr BESS for Regulation
2041		
2042		
2043		
2044		
2045	Install 30 MW Future Wind, Install Two - 20 MW Future PV	Install 30 MW Future Wind, Install Two - 20 MW Future PV

Table K-120. Maui PSIP Final Theme 2 Cases 54 & 53

Lanaʻi Cases

Theme 1

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		1
	2015 EIA Reference	No	Yes	Yes		2
	2015 EIA Reference	No	No	Yes		3
	Feb 2016 EIA STEO	Yes	Yes	Yes		5
	Feb 2016 EIA STEO	No	Yes	Yes		6
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	11
	2015 EIA Reference	No	No	No	Final	12

Table K-121. Lanaʻi Theme 1 Cases

Theme 3

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		9
	Feb 2016 EIA STEO	Yes	Yes	Yes		10
Market DG-PV	2015 EIA Reference	No	Yes	No		7
	Feb 2016 EIA STEO	No	Yes	No		8
	2015 EIA Reference	No	No	No	Final	13
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	14

Table K-122. Lanaʻi Theme 3 Cases

Lana'i Cases 1 & 2

Case Name	Case 1	Case 2
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	2015 EIA Reference
2016		
2017		
2018		
2019		
2020	2 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW Wind, 1 MW 4 hr LS BESS	1 MW Wind, 1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW 4 hr LS BESS

Table K-123. Lana'i Cases 1 & 2

Lana'i Cases 3 & 4

Case Name	Case 3	Case 4
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	3 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW Wind

Table K-124. Lana'i Cases 3 & 4

Lana'i Cases 5 & 6

Case Name	Case 5	Case 6
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	2 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW Wind
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW 4 hr LS BESS

Table K-125. Lana'i Cases 5 & 6

Lanaʻi Cases 7 & 8

Case Name	Case 7	Case 8
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	2 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		1 MW Wind
2041		
2042		
2043		
2044		
2045	1 MW Wind	

Table K-126. Lanaʻi Cases 7 & 8

Lana'i Cases 9 & 10

Case Name	Case 9	Case 10
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	2 MW Wind	2 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW Wind, 1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045	1 MW 4 hr LS BESS	1 MW Wind

Table K-127. Lana'i Cases 9 & 10

Lana'i Final Theme 1 Cases 11 & 12

Case Name	Case 11	Case 12
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017		
2018		
2019	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2020	3 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	1 MW Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	1 MW Wind	1 MW Wind

Table K-128. Lana'i Final Theme 1 Cases 11 & 12

Lana'i Final Theme 3 Cases 13 & 14

Case Name	Case 13	Case 14
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2020	3MW Wind	3MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Wind	1 MW Wind
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW Wind	1 MW Wind
2041		
2042		
2043		
2044		
2045		

Table K-129. Lana'i Final Theme 3 Cases 13 & 14

Molokaʻi Cases

Theme 1

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		1
	2015 EIA Reference	No	Yes	Yes		2
	2015 EIA Reference	No	No	Yes		3
	Feb 2016 EIA STEO	Yes	Yes	No		4
	Feb 2016 EIA STEO	No	Yes	No		5
	Feb 2016 EIA STEO	No	No	No		6
	Feb 2016 EIA STEO	No	No	Yes		11
	2015 EIA Reference	No	No	No	Final	16
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	17

Table K-130. Molokaʻi Theme 1 Cases

Theme 3

DG-PV Forecast	Fuel Forecast	Biomass	Must Run	BESS	Plan	Case
High DG-PV	2015 EIA Reference	Yes	Yes	Yes		9
	Feb 2016 EIA STEO	Yes	Yes	No		10
Market DG-PV	2015 EIA Reference	No	Yes	Yes		7
	Feb 2016 EIA STEO	No	Yes	No		8
	Feb 2016 EIA STEO	No	No	Yes		12
	2015 EIA Reference	No	No	Yes		13
	Feb 2016 EIA STEO	No	No	No	Sensitivity on Final	14
	2015 EIA Reference	No	No	No	Final	15

Table K-131. Molokaʻi Theme 3 Cases

Moloka'i Cases 1 & 2

Case Name	Case 1	Case 2
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	2015 EIA Reference
2016		
2017		
2018		
2019		
2020	4 MW Wind	4 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041		
2042		
2043		
2044		
2045		1 MW 4 hr LS BESS

Table K-132. Moloka'i Cases 1 & 2

Moloka'i Cases 3 & 4

Case Name	Case 3	Case 4
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	5 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	
2041		
2042		
2043		
2044		
2045		

Table K-133. Moloka'i Cases 3 & 4

Moloka'i Cases 5 & 6

Case Name	Case 5	Case 6
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	3 MW Wind	4 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	1 MW Wind	

Table K-134. Moloka'i Cases 5 & 6

Moloka‘i Cases 7 & 8

Case Name	Case 7	Case 8
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	4 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	1 MW Wind
2041		
2042		
2043		
2044		
2045		

Table K-135. Moloka‘i Cases 7 & 8

Moloka'i Cases 9 & 10

Case Name	Case 9	Case 10
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018		
2019		
2020	4 MW Wind	3 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030	1 MW Biomass	1 MW Biomass
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040	1 MW 4 hr LS BESS	
2041		
2042		
2043		
2044		
2045		

Table K-136. Moloka'i Cases 9 & 10

Moloka'i Cases 11, 12, & 13

Case Name	Case 11	Case 12	Case 13
Case Label			
DER Forecast	High DG-PV	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	Feb 2016 EIA STEO	2015 EIA Reference
2016			
2017			
2018			
2019			
2020	5 MW Wind	5MW Wind	5MW Wind
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS	1 MW 4 hr LS BESS
2041			
2042			
2043			
2044			
2045		1MW Wind	1MW Wind

Table K-137. Moloka'i Cases 11, 12, & 13

Moloka'i Final Theme 1 Cases 16 & 17

Case Name	Case 16	Case 17
Case Label		
DER Forecast	High DG-PV	High DG-PV
Fuel Price	2015 EIA Reference	Feb 2016 EIA STEO
2016		
2017		
2018	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2019		
2020	5 MW Wind	5 MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		

Table K-138. Moloka'i Final Theme 1 Cases 16 & 17

Moloka‘i Final Theme 3 Cases 14 & 15

Case Name	Case 14	Case 15
Case Label		
DER Forecast	Market DG-PV	Market DG-PV
Fuel Price	Feb 2016 EIA STEO	2015 EIA Reference
2016		
2017		
2018	Install two - 5 MVA Synchronous Condenser	Install two - 5 MVA Synchronous Condenser
2019		
2020	5MW Wind	5MW Wind
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045	1MW Wind	1MW Wind

Table K-139. Moloka‘i Final Theme 3 Cases 14 & 15

L. EPRI Reserve Determination

HECO/EPRI RESERVE DETERMINATION 2015/2016 PROJECT SUMMARY

The overall goal of this project is to use methods developed by EPRI as part of their research into the impacts of wind and solar on system operations to propose a new HECO method for determining operating reserve requirements. Since HECO is an island system with high sensitivity to frequency swings compared to mainland interconnections, the project is focused on short-term frequency regulating reserve. Using a multi-cycle power system operations model (one that simulates the multiple decision-making procedures taken in real operations), the study will analyze costs, area control error (ACE) and frequency with the current reserve requirement determination method and the proposed reserve method. This will be done for both current and future renewable penetration on the Oahu system. The study will also look at sensitivities including utilization of battery energy storage and use of regulation reserve during renewable ramping periods combined with a generating contingency event.

Using multi-cycle models to represent the various decisions made by HECO operators, and stochastic representation of wind, solar, load and outages, short term operations are being examined. This will allow for better understanding of how reserves are currently being used, and how new methods, including those based on the stochastic nature of wind, solar and load, could improve upon the optimal amount of reserve needed for the system. The findings from this study will inform the development of new short term operational tools to manage wind and solar variability and uncertainty. This may include conditional rules for procurement and deployment of reserves. It is also expected to examine the operation of a battery storage unit that will be installed and used for providing reserves. By adding progressively more detail to the model, each of the above can be examined. At the end of the project, EPRI will work with HECO to ensure that lessons learned can be transferred to operating practices and their EMS tools. The aim is not, however, to develop online operating tools, but rather examine some of the potential operating solutions through realistic simulations.

The team is using the FESTIV simulation tool which incorporates unit commitment, economic dispatch, automatic generation control, and contingency-based operator action. The tool is unique in being able to simulate the long-term scheduling and commitment of resources days and hours ahead, while also simulating the fast second-to-second control and frequency impacts of the system. So far, the following work has been accomplished to date:

- The team has collected 8 weeks of high-resolution load, conventional generation and renewable data and constructed the input files necessary to run the simulation tool
- The team has developed a module to better simulate frequency of the HECO system using the HECO frequency bias and ACE.
- The team has developed a module to mimic HECO's "equal lambda criterion" AGC simulation model, which determines production levels based on HECO generator quadratic cost functions.
- The team has incorporated numerous reliability must run, derate, and other specific rules to benchmark unit generation, frequency, and ACE.
- The team has performed simulations of all 8 weeks using the base case reserve requirement method.

Going forward the team will be analyzing the frequency and ACE impacts of all 8 weeks with the current reserve methodology, the EPS-proposed reserve methodology, and the EPRI research reserve methodology. The team is also evaluating the impact of allowing all units but Kahe5 and Kahe6 as flexible (rather than must-run) to understand how this will change the benefits and impacts of the reserve methodologies. It will evaluate the periods where greater imbalance was occurring, and using probabilistic renewable generation forecasts and variability statistics, propose a reserve requirement determination method with improved performance based on economic or reliability factors. All but the EPRI research reserve methodology will be completed by the end of March. A preliminary evaluation of the benefits of implementing the EPRI methodology is expecting by the end of Q2 2016, and the final analysis and report for the entire effort is expected by end of Q4 2016.

Assessment of EPS Reserve Methodology

Here we provide an assessment of the EPS proposed reserve methodology based on the report "Proposed HECO Regulation – From Measured Wind and Estimated Solar Data" published August 5, 2014 and provided to EPRI by HECO. Based on a high-level review of the proposed approach, EPRI's assessment indicates a more efficient reserve procurement approach can be specified while still maintaining a satisfactory level of reliability. We describe suggestions on improvements below in four improvement categories.

Improvement 1: Assumption of correlation of wind and solar, and with load

In the EPS proposal, the total regulation requirement is given in terms of separate requirements for wind and solar, based on covering large ramps of each type of resource. By adding the separate requirements for covering wind and PV ramping in isolation to get to total required regulation, the method is essentially assuming that wind and solar are perfectly correlated (i.e., the largest wind ramp will happen at the same time as the largest solar ramp). Just as the EPS proposed method calculates reserve requirements based on total wind or total solar rather than summing up the requirement to cover the ramping of individual wind plants and individual solar plants, the reserve determination requirement should consider the total ramp from total renewables based on output level rather than each technology individually. For example, it may be that the EPS method requires substantial regulation requirement to cover wind ramps that are ramping down during a period when solar is ramping up such that the net variability is not as significant. Similarly, the reserve requirement should also be evaluated with load to cover the net load variability and not just the aggregate renewable ramping. Requirements can use multi-dimensional lookup tables for regulation requirements (e.g., for particular wind, solar, and load conditions, carry X MW of regulation reserve). With further analysis, this enhancement to the method can reduce the amount of reserve while having negligible reliability impacts. This would involve looking at the relationship between wind, solar and load variability and, based on this relationship, developing a requirement to cover the maximum largest ramps. One of the key challenges here will be ensuring sufficient representative data is available such that the worst case events can be identified; if there is not sufficient confidence in this, then some margin may be needed above the amount that data analysis may identify as needed.

Improvement 2: 1:1 Ratio and Percentage Level cap

The EPS approach seems to use a 1:1 approach that requires 1 MW of reserve for every MW of production, up to a certain percentage level of wind or solar, above which no incremental reserve requirements are needed. We were unable to determine why these approaches were taken based on the data available to EPRI; the use of 1:1 ratios and the cap percentage above which no more is needed both seem arbitrary. The figure below shows that application of the EPS requirement in red for PV ramping data from MECO results in holding more than twice the reserve required to cover ramps for some lower PV levels and a deficit in reserve to fully cover PV ramps for some higher PV levels . Even if the system required 100% compliance of meeting the 20-minute ramp, a segmented curve that doesn't keep the arbitrary 1:1 ratio can be used as shown below in yellow. This would meet all of the historical ramps based on the data shown, such that over-procuring reserve requirements would be significantly reduced. Even if a margin is desired, it can be seen that the yellow line is significantly lower at lower PV output. Applying a segmented reserve requirement curve approach for each operating company may reduce costs by reducing unnecessary reserves while providing greater compliance by covering ramp events between 20 and 30 MW outputs in this example that wouldn't have been guaranteed in the previous method.

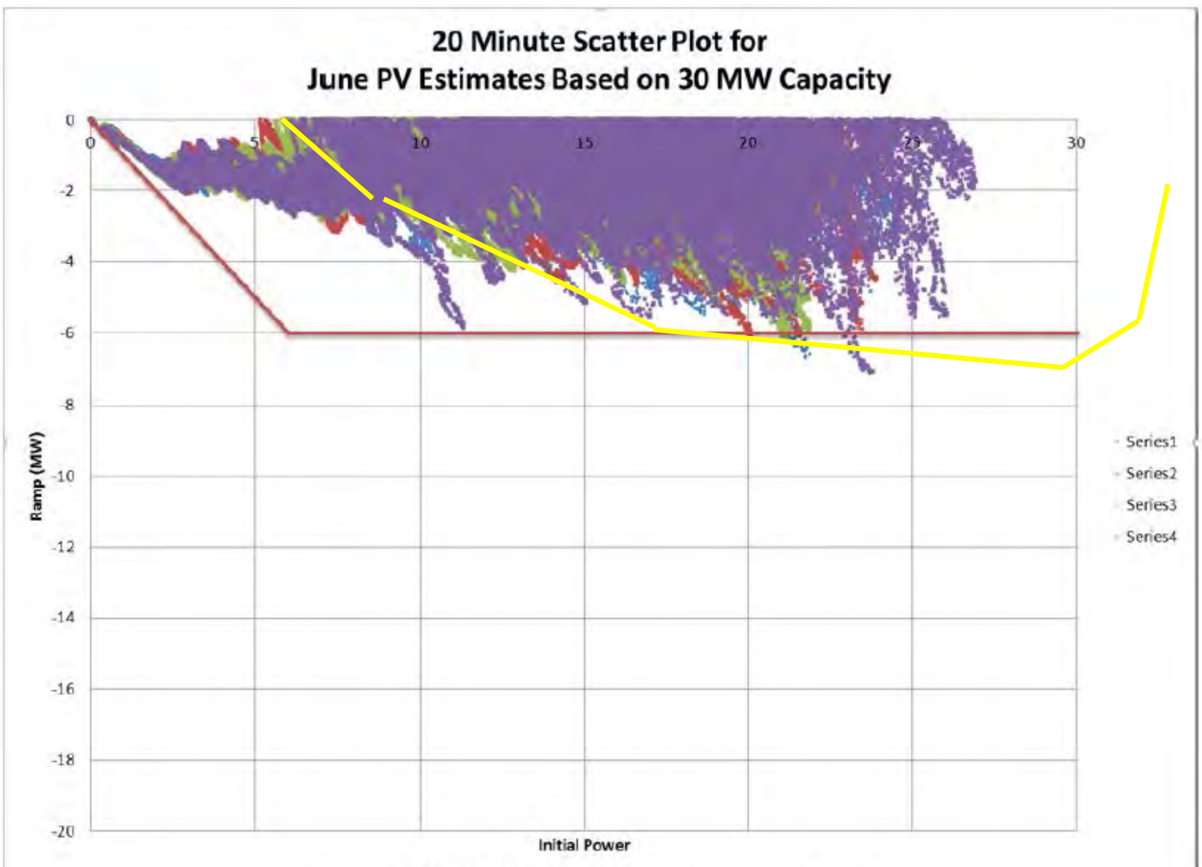


Figure 4 : MECO 20-Minute Solar Ramps for June

Improvement 3: 100% compliance assumption

In the mainland U.S. balancing compliance requirements are based on statistically ensuring that imbalances do not get large enough to trigger under-frequency load shedding for N-1 and rare, defined other credible events (e.g., n-2). For normal balancing, the current NERC standard is that the imbalance be less than some specified MW level for 90% of the time . For an interconnected system with similar peak load to HECO, the imbalance level must be less than approximately 25 MW for 90% of the time. Due to the isolated nature of all the HECO island systems, the allowable imbalance levels must be maintained lower than on mainland systems, as there are no neighboring areas to net out impacts and because frequency excursions are much larger for similar sized imbalances. However, adjusting the HECO reserve requirement to allow for potential deficiency of a few MW 1% or less of the time, is not likely to adversely impact reliability. As a hypothetical example, the segmented reserve requirement represented by the orange trace in the same MECO PV ramping chart below would likely provide 99.9% compliance for meeting its ramping requirements (based on graphical observation without reviewing data), and any imbalances would cause a deviation of less than one MW with little impact to frequency error. HECO may further improve its reserve requirement approach by reviewing its operating criteria for the level of imbalance that can cause a significant frequency deviation, any added safety margins (to account for starting frequency), and its agreed upon risk tolerance (or compliance standard) on how often allow deviations of different magnitude can be allowed.

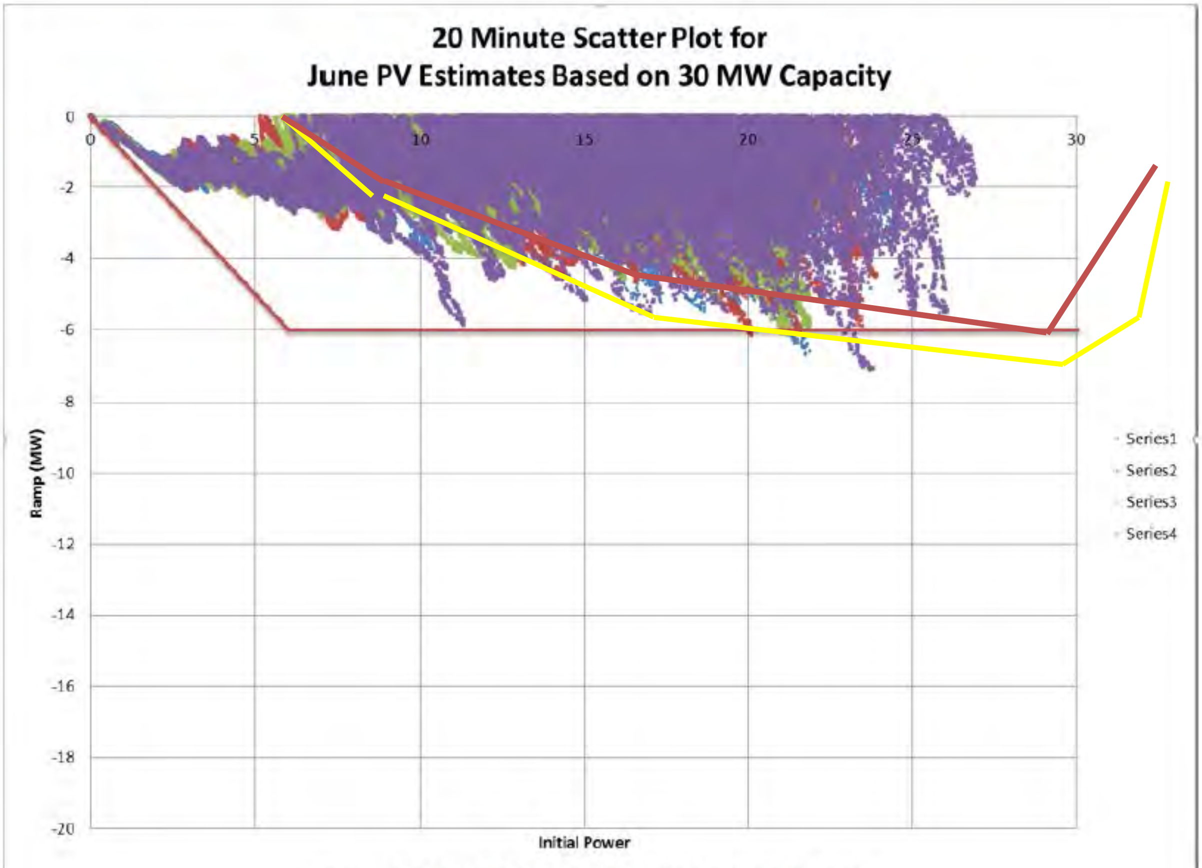


Figure 4 : MECO 20-Minute Solar Ramps for June

Improvement 4: Impact on the predictability of ramp conditions

The EPS reserve methodology determines regulation requirements based on the ramp levels of wind and solar at various output levels. However, it does not consider the predictability of those ramps. For example, solar ramp down during the evening when the sun comes down is relatively easier to meet compared to a random cloud cover that was not predicted. This is because the prediction of the ramp allows the operator to schedule the commitment of additional resources in advance such that they are prepared to turn on when the ramp occurs, and may not be needed during other periods. The predictability (or unpredictability) of the ramp can have a large impact on the reserve requirement. It is unclear as to whether this impact can increase or decrease requirements, as that would depend on the accuracy of HECO's renewable resource forecasts, and its scheduling efficiency (scheduling and commitment of resources outside of regulating resources).

Other Reserve Determination Methods that Consider Renewable Output

A number of other areas with high renewable penetrations are beginning to adjust their operating reserve requirements (mostly regulation reserve) to incorporate the impacts of renewables. A few web links to documents summarizing some of these emerging requirements are provided at the end of this section for further reference.

ERCOT, although much larger than HECO, is also an isolated balancing area, although it has relatively small DC connection with other areas. ERCOT was one of the first regions that adjusted its reserve requirements based on renewable impact and keep a level of reserve that is not constant. The following occurs in ERCOT's regulation reserve requirement methodology:

- ERCOT bases its regulation needs based on meeting 95th percentile of all ramps, based on study of data from the previous month and the same month in the previous year (e.g. when calculating requirements for March 2016, they use mid-January to mid-February 2016 data and March 2015 data).
- Requirements are calculated for each hour of the day in the following month, giving a 24 hour time series of requirements.
- ERCOT bases its regulation needs on meeting the NERC Control Performance Standard 1 that dictates how well it should balance generation and load
- The increase of regulation due to wind generation is about 0.5% of installed capacity. For 1,000 MW capacity increase in wind, the regulation requirement is increased by 4-6 MW. These requirements were based on overall impacts on imbalance to the net load
- The original level is based on previous deployments of the regulation, with regulation being used to meet overall net load imbalance

Other areas have described small changes to their regulation reserve requirements based on increased renewable penetrations. This typically includes regulation requirements that might be based on a percentage of load plus some quantity based on the expected renewable output. Most of these are not as transparent as to how they are calculated as compared to ERCOT. For example, SPP describes their regulation requirement as "based upon a percentage of forecasted load, adjusted up or down to account for resource output variability, and may vary on an hourly basis." The incremental requirements from wind generation are based on both the anticipated forecast and the anticipated hour to hour change.

Other areas in the continental U.S. are also introducing new reserve products, similar to regulation. These products, typically referred to as ramping capability or flexibility reserve, are reserve held to be used in a continuous basis (similar to regulation), but are deployed on a 5-10 minute time frame rather than a second-to-second time frame. The requirements are used primarily to accommodate for renewable forecast error and renewable output ramps. The requirements are typically based on historical renewable ramps over the time frame of interest (typically 5 minutes, 10 minutes, or 30 minutes), and expectation to meet some percentile of those ramp events (e.g., 95%). These products are now present in areas including California ISO, MidContinent ISO, and Public Service of Colorado. Others may introduce similar reserve products in the near future.

References:

Electric Power Research Institute, Reserve Determination Methods for Variable Generation: Industry Practices and the current research, Product ID 3002004242, Oct. 2014.

Ela et al., Operating reserve and variable generation, NREL tech report, 2011. Available: http://www.nrel.gov/docs/fy11osti/51978.pdf

ERCOT, Methodologies for Determining Ancillary Service Requirements. www.ercot.com/content/mktinfo/dam/kd/ERCOT%20Methodologies%20for%20Determining%20Ancillary%20Service%20Requir.zip (opens up zip file directly which contains word document)

MISO, ramp capability white paper, 2013. Available: https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf

CAISO, flexible ramping product project page: Available: https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

Use of Renewables for Active Power Management

In many parts of the country and elsewhere in the world, renewables (wind and solar power) are used for various active power ancillary services to assist in meeting energy requirements and reliability needs. We will go through different types with brief descriptions and references.

Service 1: Congestion management and redispatch

In many areas of the United States wind power is used for redispatch to maintain the energy balance and ensure transmission constraints are within their normal and contingency limits. In most of the U.S. independent system operators, wind is used to assist in congestion management. When a transmission constraint is limited, and wind may be the most efficient or only option to bring the flow within limits, the system operator will send a direction to curtail within the next five minutes and the wind resource will do so. This can also be important when thermal generation plants are at their minimum stable generating limits where they cannot back down any further and cannot turn off due to their minimum off time and start-up times when required to be on in the near future. It is feasible that curtailment of wind and/or solar could be an economic means to handle high penetrations, where it is less expensive to curtail than cycle units on and off. For example, Xcel Energy use this procedure in their Colorado service territory (which is a vertically integrated balancing authority) to allow them to turn off coal units. During nighttime periods, coal could be turned off and wind provide AGC to manage variability. This may also reduce the amount of variability present in the system, either by reducing up-ramps of wind or solar (downwards reserve) or by pre-curtailing before periods of large ramp downs in wind or solar.

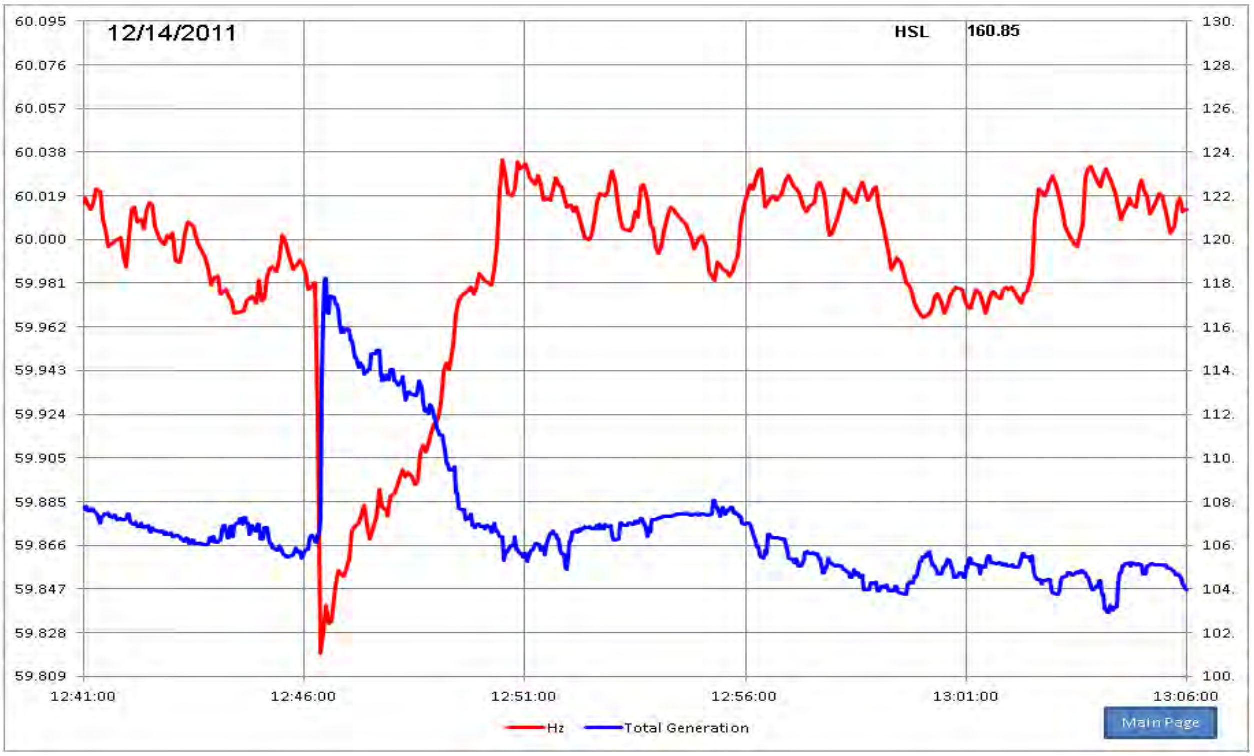
More information can be found in the following:

NYISO, Integration of wind into system dispatch, 2008. Available: http://www.ferc.gov/CalendarFiles/20090303120334-NYISO%20Wind%20White%20Paper%20October%202008.pdf

MISO dispatchable intermittent resource program: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2011/DIR%20Workshops/20110413%20DIR%20Implementation%20Workshop%20Presentation.pdf

Service 2: Frequency control

Wind power can also provide frequency control, similar to the control of the turbine governor droop, such that it can responded rapidly to system frequency to help stabilize frequency. It is able to provide fast response particularly to over-frequency events by reducing impact, as seen in the chart below. To provide sufficient under-frequency response, the plant has to be pre-curtailed which may have economic or contractual consequences. If curtailed, it is able to provide a fast response, and in ERCOT is required to do so only when curtailed for other reasons. Solar is able to perform similarly. The impact of the forecast accuracy of renewable output can also impact the ability of renewable generation to provide frequency response (particularly under-frequency response), as when the forecast is wrong, the amount of frequency response from the renewable plant may be less than anticipated. The controls to perform in this manner are readily available from the major wind turbine manufacturers, although they do need to be retrofitted to plants where they are not already installed. That said, having these controls enabled could potentially allow for other resources to be decommitted at times of high wind or solar output, when those resources can be curtailed to provide frequency response.



(Taken from ERCOT website)

http://www.nrel.gov/electricity/transmission/pdfs/wind_workshop2_05sharma.pdf

http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf (Reliability criteria in ERCOT that describes wind's participation in providing primary frequency control)

http://www.nrel.gov/docs/fy14osti/60574.pdf

EPRI and NREL organized a project, as well as associated workshops, on the above topics of active power control for wind. More details can be found at http://www.nrel.gov/electricity/transmission/active_power.html

M. Component Plans

To date, there have been four Commission Orders that have directed that the Companies create a series of component plans: Order No. 32053 (Hawaiian Electric); Order No. 31758 (Hawaiʻi Electric Light); Order No. 32055 (Maui Electric); and Order No. 33320, which reiterated most of the included in the previous Orders.

These component plans and the operating utilities to which they apply are: :

- **Fossil Generation Retirement Plan:** Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric.
- **Generation Flexibility Plan:** Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric.
- **Must-Run Generation Reduction Plan:** Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric.
- **Environmental Compliance Plan:** Hawaiian Electric and Maui Electric.
- **Key Generator Utilization Plan:** Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric.
- **Optimal Renewable Energy Portfolio Plan:** Hawaiian Electric and Maui Electric.
- **Generation Commitment and Economic Dispatch Review:** Hawaiian Electric, Hawaiʻi Electric Light, and Maui Electric.

Integrated throughout our planning and analysis, the Companies have worked toward satisfying the requirements stated in each of the component plans. Chapter 8: Action Plan also addresses our plans to meet the requirements specified by the Commission in the above referenced Orders. This Appendix M provides additional details regarding these component plans.

FOSSIL GENERATION RETIREMENT PLAN

Considerations in Retirement Plans

Our vision of providing a future with more renewable energy, while also minimizing cost impacts to customers, requires our fossil fueled generating units to be replaced with new generating resources. Although new generation resources require capital investment, we anticipate the addition of these new resources will lower future energy costs compared with the current energy mix, and over time, our customers will be able to realize the cost benefits. Retiring existing generation will also reduce dependency on fossil fuels.

Fossil generation assets are used to provide bulk power needs and for providing system reliability (i.e. adequacy of supply and system security). Because of the inertia and stability benefits of spinning generation (as opposed to inverter based resources), thermal resources have been used to keep voltage and power flows within equipment thermal limits, stabilize and regulate system frequency, and stabilize and regulate voltage.

Retirements of a thermal resource can be considered when it is no longer cost-effective to continue to operate and maintain, and when it no longer is required to serve reliability needs.

Units are considered for retirement when all of the below are true:

- The cost of maintaining and operating the unit to provide bulk power needs is more expensive than an alternative means of serving bulk demand (e.g. a new unit is would be more economical, even taking into account the capital cost of the new unit, or the aggregate capacity value of a variable renewable resource is sufficient to retire the unit).
- The unit is no longer required to meet adequacy of supply requirements (i.e. providing capacity to meet reserve margins).
- The unit is not required for system security reasons, such as offline reserves, fast-start, system restoration, or other critical functions, or are not the most economic means of meeting system security (e.g. when a different generator, BESS, DR, etc. can provide a more economical source of these essential grid services).

Retirements are evaluated by performing production simulations comparing costs and reliability metrics, with and without the resources.

The plans in this PSIP update reflect planned retirement dates of existing thermal units based on new resource energy additions consistent with each plan and an analysis of the best use of resources under a high fuel price scenario (since under a high fuel price scenario, use of less efficient thermal resources is desirable). These retirement dates may be adjusted based on further optimization including future updates to our resource plans and conditions existing at the time of the decision (e.g. actual availability of new resources, level of success of DR programs, and fuel price outlook).

The operation of each thermal resource is continually evaluated for its ability to economically provide bulk capacity and reliability services. As the need for thermal units decline, they are considered for daily or seasonal cycling.

Hawaiian Electric's Plan for Retiring Fossil Generation

We plan to deactivate or retire all existing steam generating units by 2030. In general, a generating unit will be retired two years after it is deactivated.

Table M-1 shows the retirement schedule for Hawaiian Electric thermal generation under each of the different Themes discussed in Chapter 3.

Last Year of Service	Theme 1	Theme 2	Theme 3
2020		Kahe 1,2 & 3	
2021			
2022	AES	AES Kahe 4 Waiau 3 & 4	AES
2023	Waiau 3 & 4		Waiau 3 & 4
2024		Waiau 5 & 6	
2025	Kahe 6		Kahe 6
2026			
2027			
2028			
2029			
2030	Waiau 5 & 6	Waiau 7 & 8	Waiau 5 & 6

Table M-1. Hawaiian Electric Fossil Generation Retirement Plans

The deactivation plan for all steam units was developed on a systematic basis. In order to provide the most cost reduction to the customer, we deemed it necessary to retire units in pairs because unit pairs share one control room, operator staff, and common equipment.

Hawai'i Electric Light's Plan for Retiring Fossil Generation

All existing Hawai'i Electric Light steam-generating units are to be deactivated by 2033.

Table M-2 shows the retirement schedule for Hawaiian Electric thermal generation under each of the different Themes discussed in Chapter 3. The plan(s) filed in the PSIP show potential dates of certain resources where they could be removed from service based upon the identified new renewable energy additions. The dates and resources shown are the probable dates assuming the additions, and based on analysis of which resources are operated the least under a high-fuel scenario and discussed above may be adjusted based on further optimization. If retirement is enabled through addition of a new resource, two years for the new resource to become reliable and proven will be scheduled before retirement. Generally, a resource would be used for replacement capacity for a period of time before retirement as needed while the new resource is proven.

Last Year of Service	Theme 1	Theme 2	Theme 3
2020			
2021			
2022	Puna Steam	Puna Steam	Puna Steam
2023			
2024	Hill 5		
2025			
2026	Hill 6		
2027		Hill 5	Hill 5
2028			
2029			
2030		Hill 6	Hill 6
2031			
2032			
2033			

Table M-2. Hawai'i Electric Light Fossil Generation Deactivation Plans

Maui Electric Retirement Plan

The four units at the Kahului Power Plant (KPP) are the only units planned for retirement by 2045 within the Maui Electric systems on Maui, Moloka'i, and Lana'i. As additional renewable energy resources are added to the respective systems, units on all islands will instead be deactivated. Like Units K1 and K2 at KPP today, the deactivated units could be called upon to provide capacity to the system on an as-needed basis.

KPP will be retired upon the installation of replacement generation capacity on Maui along with upgrades to the transmission system or by November 30, 2024 (to comply with environmental regulations), whichever occurs first. Current plans are to have the new capacity and transmission upgrades in place by December 31, 2022.

Table M-3 shows Maui Electric's retirement schedule for existing fossil fuel generating resources.

Last Year of Service	Theme 1	Theme 2	Theme 3
2020			
2021			
2022	Kahului 1,2,3,& 4	Kahului 1,2,3,& 4	Kahului 1,2,3,& 4
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			

Table M-3. Maui Electric Fossil Fuel Generation Retirement Plan

Background

KPP consists of four steam units totaling 35.92 MW (net) of firm generating capacity with Units K1-K4 installed in 1948, 1949, 1954, 1966, respectively. When operating, these units provide firm generation and contribute to system security by providing regulating reserve, system inertia, and voltage support to the Maui system.

Prior to 2010, K1 and K2 were operated daily from approximately 6 a.m. to 10 p.m. to serve daytime demand. In December 2010, the operation of K1 and K2 was changed to approximately 2 p.m. to 10 p.m. on alternating days to serve peak demand during the late afternoon to evening period. This change in operation was one of the Maui

Operating Measures[1] (MOMs) implemented to help reduce the amount of curtailment of energy that was anticipated when the second and third wind farms (Kaheawa Wind Power II and Auwahi Wind Energy) were added to the system. As a result, the energy produced by K1 and K2 was reduced from about 60 GWh annually, to about 15 GWh annually. This enabled the system to accept more energy from the Maui wind farms.

On September 3, 2013, Maui Electric filed its System Improvement and Curtailment Reduction Plan (SICRP). In that plan, the Company noted that in addition to implementing the remaining MOMs, it had both reduced the minimum loads on units K3 and K4 and allocated regulating reserve to those units. In 2014, K1 and K2 were deactivated as committed to in the SICRP, though they can be, and have been activated to avoid capacity shortfalls as well as for other system security requirements.

The operational changes made at KPP contributed to a significant decrease in curtailment of wind energy from 35% in the first quarter of 2013 to less than 10% since.

Environmental Regulations

In May 2013, the State of Hawaiʻi Department of Health (DOH) advised Maui Electric of new requirements relating to cooling water discharge at KPP, impacting its National Pollution Discharge Elimination System (NPDES) permit. As a result Maui Electric anticipated it would have to retire KPP by 2019, ahead of the need to meet the new cooling water discharge requirements, or implement a solution that would meet NPDES standards. This was reflected in the 2014 PSIP.

In late 2014, Maui Electric chose to pursue a 9.5-year compliance plan to be included in the NPDES permit. Inclusion of the compliance plan allows Maui Electric to continue operating KPP beyond 2019, and provides additional time to secure replacement capacity and complete the necessary transmission upgrades in Central Maui. The NPDES permit containing the 9.5-year compliance plan was approved in June 2015, giving Maui Electric until November 30, 2024 to cease water discharges at KPP, effectively requiring termination of generation at the facility at that time.

Potential alternatives (which would likely require a modification to the existing NPDES permit) to terminating the discharge of water from KPP such as a cooling tower, deep ocean discharge, and injection wells, all face a multitude of barriers (permitting, property acquisition, easements) that would jeopardize their ability to be completed before the expiration of the NPDES permit. In fact, given the need for discretionary permits, and

[1] The MOMs include (1) operating units K1 and K2 on alternating days, (2) limiting up reserve to a maximum of 50 MW, (3) allocating up reserve to the KPW II BESS, (3) allocating 3 MW down reserve to the KWP II BESS, and (4) modifying automatic generation controls (AGC) to allow implementation of the MOMs.

cooperation and coordination from other landowners, it is questionable whether these solutions could be implemented at all.

Other Considerations

In addition to addressing the concerns of the Commission regarding the curtailment of wind energy, and meeting environmental requirements, there are other factors which further solidify Maui Electric's decision to retire KPP, including:

- Tsunami Mitigation – given its location along the Kahului shoreline, KPP is very susceptible to damage should Maui be impacted by a tsunami. As the need arises and is appropriate, Maui Electric will replace generating assets with generating facilities out of the tsunami inundation zone that will make the Maui grid more resilient against such a natural disaster.[2]
- Renewable Energy Integration – the reduction to base load generation on Maui associated with retiring KPP will provide additional headroom for accepting as-available renewable energy. Quick starting units will also be sought to replace KPP's generating capacity, allowing greater operational flexibility.

Replacement Generation

Absent any replacement capacity, the retirement of KPP will result in a reserve capacity shortfall of at least 40 MW. Meanwhile system peaks on Maui have been trending upward, driving the potential need for even more future capacity. In order to ensure adequate generating capacity for Maui's customers, Maui Electric will be requesting a docket be opened to initiate the procurement of the necessary capacity.

Among the characteristics that will be required of the units will be quick-start ability, which will assist with the integration of as-available renewable energy onto the grid. Additionally, renewable energy solutions that can meet the operational requirements of the replacement capacity and be cost effective to customers will be encouraged to participate in the procurement process.

A portion of the replacement capacity may also be located in South Maui in order to address existing under-voltage risks in that part of the island. The generation would serve as a non-transmission alternative (NTA) to upgrading the transmission line serving South Maui, which has received significant community opposition due to the aesthetic impact of the proposed upgrades.

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[2] Both KPP and Ma'alaea Power Plant are located in the tsunami inundation zone. As a result, the threat of damage from a tsunami plays in a role in Maui Electric's decisions on where to locate future generation or other assets.

The candidate plans considered a number of options for the replacement capacity for KPP; the plan development process is discussed in Chapter 3. Ultimately, the resource will be selected based on the option that provides the best value to Maui Electric's customers.

Along with Maui Electric's efforts to procure replacement capacity, we will continue to pursue non-generation alternatives to help meet the island's capacity needs, while minimizing future traditional generation. These alternatives include, but are not limited to, demand response, time-of-use rates, and energy storage.

Central Maui Transmission and Distribution Projects

The Central Maui region plays a critical role on the island of Maui as it is the center of government and commerce. The Central Maui region is served by both the 69kV system and the 23 kV system with power provided by the Ma'alaea Power Plant (MPP) and KPP. However, the retirement of KPP primarily impacts the 23kV system, which serves the areas of Kahului, Wailuku, and Wai'ehu. Over 13,000 Maui Electric customers are on the 23 kV system, including University of Hawai'i Maui College, Baldwin High School, Maui High School, Maui Mall, Community Clinic of Maui, Armory Reserve, Maui Arts & Cultural Center, Hale Makua, Maui Beach Hotel, Maui Sea Side Hotel, Wallace Theaters, Maui VET Center, War Memorial Stadium, Nan Inc., Sack N Save, Foodland, Young Brothers, State of Hawai'i Department of Transportation Harbors Division, County of Maui water facilities and waste water treatment pumps, Central Maui Landfill, and Ameron. It is imperative to continue to provide reliable, electrical services to this area.

After the retirement of KPP, the Central Maui load on the 23 kV system will be served by MPP, and the capacity-constrained MPP-Waiinu and MPP-Kanaha 69kV transmission lines. The Central Maui transmission system will need to be upgraded to ensure stability of the Maui system. In addition, the 23 kV system has three 69/23 kV transformers that connect the 23 kV system and the 69 kV system. These transformers are located at Waiinu, Kanaha, and Pu'unene substations. The loss of either the MPP-Waiinu 69kV or the MPP-Kanaha 69kV transmission lines (i.e. defined as a N-1 contingency) during higher system load conditions results in under voltages and thermal overload conditions.

Additionally, under the contingencies noted above, there is the potential for overloads to occur on the remaining transformers, depending on the load. If there is too much power being transferred to the 23 kV system from the 69 kV system, the system may not be able to manage the transfer and can experience a voltage collapse and/or load shedding scenarios in the event of further system disturbances or unanticipated loadings levels in the Central Maui region. In order to support the retirement of KPP, and as part of grid modernization efforts, Maui Electric is proposing to upgrade the existing 23 kV Waiinu-Kanaha line to 69 kV, which includes 69kV upgrades to the existing Waiinu and Kanaha substations, as well as a major addition to the existing Kahului Substation, and reconductoring (i.e. increase the transmission line capacity) of the existing MPP-Waiinu and MPP-Kanaha 69kV transmission line.

These upgrades address the required N-1 Transmission Planning criteria, maintain required voltage limits, strengthen and complete the critical 69kV link for Central Maui, and allow for continued and reliable service under contingency conditions (i.e. during system maintenance and forced outages) and higher system load conditions.

The Kahului Power Plant Retirement-Comprehensive Assessment (included in the 2014 Maui Electric PSIP) provides the technical analysis to locally reduce the amount of load and help with the voltage issues on the 23 kV system. In addition to upgrading the transmission system, NTAs such as internal combustion distributed generation (DG), battery energy storage system (BESS), and synchronous condensers were considered; however, the analysis concluded that upgrading the transmission and distribution system is the most technically sound and viable option.

In an effort to more thoroughly investigate NTA options, a third party NTA study was conducted in a joint effort by the engineering and planning firms of Tetra Tech and CH2M Hill. The NTAs assessed included:

- Firm Dispatchable Distributed Generation (FDDG) – similar to conventional generation, available to the utility for immediate dispatch
- Distributed Standby Generation (DSG) – emergency generators
- Photovoltaic/Battery (PV/Battery) – combination
- Firm Dispatchable Generation/Battery Energy Storage System (FDG/BESS)
- Synchronous Condenser
- Static Capacitor Banks
- Demand Response (DR)

The CH2MHill / TetraTech report identified Firm Dispatchable Distributed Generation (FDDG) as the only feasible non-transmission alternative that would effectively address the contingency overload and under voltage conditions in Central Maui. The TetraTech/CH2MHill report concluded: The only NTA that addresses the loss of generation from KPP, supports voltage stability, and prevents thermal overloads is the addition of new FDDG on the 23 kV system that is strategically located to serve the Kahului, Waiinu, and Wailuku areas. A potential site was identified in the Central Maui area; however, the County of Maui indicated that it does not consider FDDG in the Central Maui region as a viable NTA citing noise, traffic, and emissions concerns. Similarly, a major real estate developer noted their concerns with the placement of FDDG in the Central Maui area citing impacts to future residential development plans.

In addition, the FDDG option poses transmission issues as this option requires major transmission line upgrades from the FDDG to the existing transmission system, as well as a redundant transmission line tie-in (to address the N-1 criteria) to the existing 23kV system. Without the NTA FDDG option, Maui Electric will need to upgrade the existing 23 kV system.

Based on analyses completed to date, the Central Maui transmission and distribution projects provide the most certain path toward ensuring continued reliability and operational flexibility in the Central Maui area. Other options are subject to far greater uncertainty regarding the potential to provide the necessary remedies prior to retirement of KPP.

The completion of the transmission system upgrades and the acquisition of replacement generating capacity are both targeted for completion by the time KPP is schedule to retire in 2022. Given the magnitude and complexity of both of these projects, the target retirement date provides a prudent amount of schedule flexibility ahead of the 2024 expiration of the NPDES permit, however work towards these efforts will have to begin this year.

Capacity Value of Variable Generation and Demand Response

In evaluating whether firm capacity generators can be retired and replaced with new renewable resources, the reliable contribution of those resources to firm generation must be considered.

Wind and solar are variable generating resources. Therefore, determining their capacity value (ability to replace firm generation) with a high level of confidence is a considerable challenge. This determination, however, is a critical exercise to ensure that customer demand is met and system reliability is maintained.

Capacity Value of Wind Generation

The determination of when additional firm capacity is needed for Hawaiian Electric, in part, based on the application of Hawaiian Electric's generating system reliability guideline, which is 4.5 years per day loss of load probability (LOLP). The capacity value of existing and future wind resources is determined through an LOLP analysis that incorporates this guideline. The wind resources' contribution to serving load is reflected in the LOLP calculations. Accordingly, wind resources' contributions to capacity are dependent upon the composition and assumptions in each plan. Future LOLP analyses that incorporate additional wind resources may affect the actual capacity value of existing wind resources.

For Hawaiʻi Island and Maui, the planning criteria are based on a 30% capacity margin and do not include LOLP. The capacity value of wind is based on historical data collected from each wind facility. The capacity value is established based on the daily historical the availability of the wind resource to serve demand during the peak periods when capacity is needed.

At this time, there are no existing wind facilities on Lanaʻi and Molokaʻi. However, if Lanaʻi and Molokaʻi develop wind facilities in the future, historical data would be required to establish the capacity value of a wind facility on Lanaʻi and Molokaʻi. It should be noted that the established capacity value differs on Oahu, Maui and Hawaiʻi Island due to varying wind regimes.

Hawaiian Electric Capacity Value of Wind. Based on historical 2013 Oʻahu wind data, the aggregate capacity value of the two existing wind farms (30 MW Kahuku Wind and 69 MW Kawailoa Wind) determined through an LOLP analysis is approximately 10 MW, or about 10% of the nameplate value of the existing wind resources.

Maui Electric Capacity Value of Wind. The aggregate value of the three existing wind farms' (30 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, and 21 MW Auwahi Wind Energy) contribution to capacity planning is 2 MW based on historical examination of available wind capacity during the peak period hours.

The capacity value of future Maui wind farms for PSIP modeling purposes is 3% of the nameplate value of the facility.

Hawaiʻi Electric Light Capacity Value of Wind. The aggregate capacity planning value of the two existing wind farms (20.5 MW Tawhiri wind farm and 10.56 MW Hawi Renewable Development wind farm) is 3.1 MW. This is based on an historical examination of available wind capacity during the peak period hours. The capacity value of the hydroelectric facilities is 0.7 MW using the same methodology used to determine the capacity value of wind.

The capacity value of future wind farms for PSIP modeling purposes is 10% of the nameplate value of the facility.

Capacity Value of Solar Generation

The capacity value of existing and future utility-scale and DG-PV is 0, using the same capacity valuation methodology used for the wind and hydroelectric resources. This result is driven by the fact that variable PV does not produce during the utility's peak periods (that is, evenings). It is the utility's net peak demand that determines the need for additional capacity.

Capacity Value of Demand Response

The estimated megawatt potential from the Residential and Small Business Direct Load Control Program, Commercial and Industrial Direct Load Control Program, Customer Firm Generation Program, and Time-of-use Programs are included in PSIP capacity planning based on updated program potential received in March 2016 for this PSIP Update.

GENERATION FLEXIBILITY PLAN

Hawaiian Electric: Increasing Operational Flexibility of Existing Steam Generators

Hawaiian Electric has reviewed current generating unit operation, previous cycling and turn-down studies, Electric Power Research Institute (EPRI) publications, and other relevant industry literature. We have taken a holistic approach to operational flexibility and are working to change procedures and policies accordingly. Historic limitations such as having all burners in service are being evaluated and modified as applicable. Flexibility in this context refers to unit turn down, on/off cycling (daily cycling), and ramp rates. These items are not one or the other, but rather optimizing each of them.

On/Off (Daily) Cycling

Enabling the base loaded units to operate in an on/off cycle mode (that is, daily cycling) would maximize variable renewable generation by lowering the amount of must-run generation on the power system. Kahe 1–4 and Waiau 7 and 8 will be able to cycle daily as necessary. It is unlikely that Waiau 7 and 8 will cycle because system reliability criteria currently require two units to be online at Waiau at all times. We will, however, be modifying procedures and practices for when or if it becomes necessary. Kahe 1–4 will be able to cycle daily as necessary. Based on preliminary testing, it is expected that Kahe 1–4 and Waiau 7 and 8 will be able to perform "hot start ups" in 3.5 hours or less (that is, the startup time from "putting fires in the boiler" to "firm" (ready for full dispatch) will be 3.5 hours or less).

The ability to change operation from baseload to cycling is largely based on procedures, training, and technical review of the units' capabilities. Cycling increases maintenance and the wear and tear on the equipment. We do expect this and envision the need to implement improvement projects to enhance the cycling ability as necessary. Potential modifications would include enlarging super heat header drains, reheat header drains, and turbine throttle drains to allow for better temperature control during startup. Additional potential modifications include nitrogen gas blanket systems to prevent air leakage during shutdown and turbine bypass systems to protect the reheat section of the boilers. Projects are to be selected based on anticipated cycles and benefit to the system and for customers.

In June 2013, a cycling test was conducted on Kahe 3; we successfully demonstrated the ability to cycle each day from June 16–20. The average startup time was 2.6 hours. The demonstration test proved that the 90 MW steam units are capable of daily cycling.

We are also evaluating our startup practices on Waiau 5 and Waiau 6, which are already cycled daily, and expect to improve their start times to be consistent with what is planned for Kahe 1–4 and Waiau 7 and 8.

Kahe 5 and 6 are not suitable for daily cycling. The units have operating constraints that make daily cycling challenging or infeasible. However, Kahe 5 and 6 are candidates for seasonal layup should that provide benefit for the system operation.

Expanded Turn Down Range

The baseload units are also being evaluated for expanded turndown to lower loads. Currently the minimum load on Kahe 1–4 and Waiau 7 and 8 is 25 MW (gross). To achieve further lower minimum loads, we reviewed EPRI publications, OEM documentation, a 1992 Hawaiian Electric/Stone & Webster Variable Pressure Operation study, a Hawaiian Electric/Stanley Consultants Flexibility Study, and miscellaneous industry publications. In the previous Hawaiian Electric empirical studies, the limitations to turn downs were evaluated. In most cases, changes to procedures and policy will allow reduction in defined minimum load points. For example, modification of requirements for maintaining drum pressure and 'all' burners in service allow for much improved unit flexibility. A circulation study for low load conditions on Kahe 1 is being conducted. Further studies will be recommended based on the outcome of the Kahe 1 circulation study. No major limitations are expected and recommended modifications will be considered based on significance, cost, and value.

Kahe 1–4 and Waiau 7 and 8 are expected to have unit minimums reduced to 5 MW (gross). Reducing unit minimums to 5 MW (gross) will provide enhanced flexibility to the power system as the unit is providing almost zero net output.[3] For this operating condition, the unit could ramp up to full load without having to proceed through a startup and synchronization protocol. Depending on the duration of the low load, operating in this condition will provide the same benefits as taking the unit offline while using less fuel than for a startup. Exact economics are being further evaluated but operating at 5 MW (gross) for 6 hours appears to use about the same amount of fuel as one hot start up. More importantly, with the generating units operating at 5 MW (gross), they still provide ancillary services not provided by variable generation, including dispatchable VARS, system inertia, and short circuit current.

During the period of June 16–20, 2014, a demonstration of low load operation was conducted on Kahe 3; it was operated for extended duration at 5 MW (gross) with reduced drum pressure. Boiler, turbine, and balance of plant equipment were monitored

[3] The auxiliary load is approximately 4 MW, and the output to the system is approximately 1 MW (net).

for performance and limitations that may hinder the low load operation. All required operating parameters remained within limitations.

Operating at such reduced minimum loads and then ramping to higher loads would induce large thermal cycles on the equipment. While the thermal cycle is less than that of daily cycling, there is still associated wear and tear and increased maintenance associated with such operation. While procedural changes, operating policy modification, and operator training represent the largest part of enabling enhanced turndown, certain improvements will certainly enhance operational flexibility. Modifying the boiler feed pumps to operate in variable speed will greatly enhance the capabilities of the condensate system. At the reduced loads, the current fixed speed pumps operate well off their best efficiency points. At low loads, the existing pumps operate in a manner that will compromise reliability and increase maintenance cost. Similarly, the feed regulator valves operate at a point that will compromise reliability and increase maintenance. Variable speed boiler feed pumps is an example of a capital improvement that will enhance unit flexibility. Variable speed force draft fans will provide similar improvement in operational flexibility. Control system tuning will also be necessary to improve operation at low loads and to automate some manual operations.

At megawatt levels less than 20 MW (gross), some form of sliding (that is, reduced) drum pressure is necessary for operations of Kahe 1–4 and Waiau 7 and 8. This reduced pressure operations helps reduce thermal stress on the steam turbine and improves circulation in the boiler tubes. System consequences need to be considered when operating units at this reduced pressure. Specifically, unit response to system disturbances will not be as robust as with the unit at full pressure. The unit with multiple burners removed from service and at reduced pressure means reduced capacity at these low loads. The units will not be able to ramp as fast with the reduced pressure. However, depending on system conditions, the benefits of reduced minimum loads are more valuable than negative implications.

Kahe 5 minimum load will also be reduced. Work and testing will be conducted to prove that Kahe 5 can safely and continuously operate at reduced pressure, and with less than all burners in service at load down to 25 MW (gross). Kahe 6 minimum load will remain at 45 MW (gross). Kahe 6 has emission limitations that will prevent operation below the current minimum of 45 MW (gross).

Ramp Rates

Kahe 1 and 2 and Waiau 7 and 8 will have adjusted ramp rates of 4 MW per minute at full pressure when in the normal operating range (that is, at loads above 30 MW gross). Control tuning and enhancement will be necessary to allow for this change. At reduced load pressures, ramp rates are estimated to be 2 MW per minute.

Kahe 3 and 4 have modern turbine control systems and therefore have an enhanced ability to run in coordinated control. Kahe 3 and 4, when at full pressure and in the normal operating range (above 30 MW), will be able to ramp at 5 MW per minute. At reduced load and pressure, the unit will be able to ramp at 2 MW per minute.

Kahe 5 and 6, when at full pressure and in the normal operating range, will be able to ramp at 3 MW per minute. Kahe 5, when at reduced pressure and load, will be able to ramp at 2 MW per minute.

Ramp testing and tuning will be conducted on each unit. Proposed ramp rates are based on testing conducted in the 2009–2012 time frames. Enhancements to coordinated control systems logic will be necessary to ensure these rates are achieved without negative consequences. Upgrades to the GCRTU (communication and control between the generating unit and System Operation) will also enhance the ability to improve ramp rates. These projects are already planned.

Operational flexibility will be improved on our generating units. The units will be able to operate in modes that best meet system demands. Table M-4 summarizes these unit-operating conditions.

Unit	Current		Near Future				
	Ramp Rate	Pmin	Ramp Rate	Pmin (MWg)	Burners Pulled	Pmax (at Pmin)	Hot Start Time Online/Full Load (hours)
Kahe 1 NOP	2.5	25	4	25	1	86/86	2.5/3.5
Kahe 1 NOP	—	—	4	20	2	69/86	—
Kahe 1 VPO (900 psi)	—	—	2	5	4 (estimated)	43	—
Kahe 2 NOP	2.5	25	4	25	0	86/86	2.5/3.5
Kahe 2 NOP	—	—	4	20	0	86/86	—
Kahe 2 VPO (900 psi)	—	—	2	5	4 (estimated)	43	—
Kahe 3 NOP	2.5	25	5	25	0	90/90	2.5/3.5
Kahe 3 NOP	—	—	5	20	3	72/90	—
Kahe 3 VPO (900 psi)	—	—	2	5	8–9	45	—
Kahe 4 NOP	2.5	25	5	25	1	89/89	2.5/3.5
Kahe 4 NOP	—	—	5	20	3	66/89	—
Kahe 4 VPO (900 psi)	—	—	2	5	8–9	45	—
Kahe 5 NOP	2.5	45	3	70	0	142/142	4/6
Kahe 5 NOP	—	—	—	45	2	135	—
Kahe 5 VPO	—	—	2	25	varies	—	—
Kahe 6 NOP	2.5	45	3	45	2	135	—
Waiau 7 NOP	3	25	4	25	1	87/87	2.5/3.5
Waiau 7 NOP	—	—	4	20	3	69/87	—
Waiau 7 VPO (900 psi)	—	—	2	5	8–9	—	—
Waiau 8 NOP	3	25	4	25	1	90/90	2.5/3.5
Waiau 8 NOP	—	—	4	20	3	69/90	—
Waiau 8 VPO (900 psi)	—	—	2	5	8–9	—	—

NOP = normal operating pressure

VPO = variable pressure operations (hybrid)

Table M-4. Hawaiian Electric Ramp Rate Improvements

Maui Electric Generation Flexibility Plan

Maui Electric has implemented many changes in our generation fleet to increase flexibility and renewable acceptance. These have previously been described in our System Improvement and Curtailment Reduction Plan (SICRP) and subsequent annual updates and included:

- Implementation of the Maui Operation Measures
- Reduction in the number of baseloaded units
- Deactivation of KPP units 1 and 2

- Lowering of the minimums on KPP units 3 and 4
- Study and implementation of new regulating reserve requirements
- Automation of curtailment though our Automatic Generation Control (AGC) system

The existing Maui Electric generation fleet has operating characteristics that are quick starting, flexible, fuel-efficient, and dispatchable to accommodate the integration of existing and additional variable renewable energy resources without significant curtailment.[4] Quick-starting generation has the ability to remain off-line until it is required to support the system, such as during a large down ramp event when the wind or solar resources suddenly become unavailable. Other units that may need additional time to start and connect to the system will need a resource to bridge the time required to supply generation (for example, demand response and energy storage). Flexible generation refers to units that can be held off-line until called upon for generation, allowing us to maximize variable renewable generation.

Roles of Current Generation

Kahului Power Plant. Kahului Power Plant consists of four (4) Steam units (K1, K2, K3, and K4) provide firm generation, regulating reserve, system inertia, voltage support to Central Maui, and contribute to system security. These units use an industrial fuel oil that is lower cost than diesel. As noted above, K1 and K2 units were deactivated on February 1, 2014, however, they can be reactivated in the event of a generation capacity shortfall, 23kV transmission voltage support, or other system need.

Maʻalaea Power Plant. Maʻalaea Power Plant has two (2) Dual-Train Combined Cycle units (DTCC1 and DTCC2). These units provide firm generation, regulating reserve, and system inertia. These units can start and provide generation in a relatively short time period. When operated in the dual-train combined cycle configuration, these units are the most efficient generating resources on the island. DTCC 1 is a must run generating unit that contribute to system security. Modifications are planned on this unit in January 2017 to allow it to operate at a lower capacity minimum level. This will allow more opportunity to integrate variable renewable energy when available, and transition to LNG will lower cost to customers. DTCC2 was changed from a baseload unit to an offline unit that can be operated in combined cycle or simple cycle mode when there is a capacity need or when renewable energy is not available.

Maʻalaea Power Plant also has fifteen (15) Internal Combustion Diesel units (MX1, MX2, M1, M2, M3, M4, M5, M6, M7, M8, M9, M10, M11, M12, and M13). These units provide firm generation and regulating reserve. These units can start and provide firm generation

[4] The thermal generation fleet on Lanaʻi and Molokaʻi is comprised of flexible, quick-starting units.

in a relatively short time period. Five of these units (X1, X2, M1, M2, and M3) are quick-starting units that can be used for emergency and as a transition unit to starting a larger diesel unit. (MX1, MX2, M1, M2, and M3 units do not contribute regulating reserves when they are online because they run at top load). These units will remain off-line and be available for contribution to system security and system load as needed after other off-line non-fossil fuel resources, such as DR and energy storage, have been used to its fullest availability and ability. Generator controls were upgraded on four (4) of the diesel units to enable remote monitoring and operation of the generating units for better response to system disturbances and system demands due to the increase in variable renewable resources on the system.

DTCC1, DTCC2, and M4–M13 units have operating ranges that can ramp up and down to accommodate fluctuations in the availability of variable renewable energy and/or system load.

Hana. Hana has (2) Internal Combustion Diesel units that provide firm generation and primarily provide support to the Hana area during transmission maintenance and system disturbance. These units will continue to be operated to support the Hana area.

Lana‘i-Miki Basin. Lana‘i has a centralized generating station with nine (9) Internal Combustion Diesel units that provide firm generation, regulating reserve, and system inertia. These units can start and provide generation in a relatively short time period. Generator control upgrades were completed in 2015 to enable remote monitoring and operation of the generating units. Maui Electric also has an agreement to operate a Combined Heat and Power (CHP) unit that is expected to return to service in 2017. The Lana‘i system does not have AGC and therefore the demand for electricity is shared equally between the online units in an isochronous mode of operation. Maui Electric runs a minimum number of baseloaded units on Lana‘i – typically two. The CHP unit will replace one (1) of the two (2) diesel units that provide baseload power for the system at Miki basin. When additional units are needed, they are committed in the most economical order given operational constraints. Maui Electric applied for and is awaiting approval from DOH for modifications to our air permit that allow lower minimum operating levels on the baseloaded units to accommodate the addition of more renewables to the system.

Moloka‘i–Pala‘au. Moloka‘i has a centralized generating station with nine (9) internal combustion diesel units and one (1) diesel combustion turbine that can start and provide firm generation regulating reserve, and system inertia. These internal combustion diesel units can start and provide generation in a relatively short time period. Maui Electric currently operates with two base loaded units on Molaka‘i because this is the lowest number of base loaded units that satisfy our single contingency criteria. When additional units are needed, they are committed in the most economical order given operational constraints. The Molaka'i system does not have AGC and therefore the demand for electricity is shared equally between the online units in an isochronous mode of operation. Maui Electric applied for and received approval from the DOH for modifications to our air permit that allow lower minimum operating levels on the baseloaded units to accommodate the addition of more renewables to the system. Additionally, generator control upgrades are planned to enable remote monitoring and operation of the generating units.

Hawai'i Electric Light Plan for Increasing Generation Flexibility

Hawai'i Electric Light has analyzed the operation of existing resources and planned resources. The operational plans incorporate the results of consulting work to evaluate optimization of existing resources, and build upon previous cycling and turn down studies, Electric Power Research Institute (EPRI) publications, and other industry literature. We have taken a holistic approach to operational flexibility and have incorporated into our operational and planning processes procedures and policies enabling generation flexibility. The historical operation of the Hawai'i Electric Light system included a fleet of fast-start generators; these have been leveraged as flexible resources that have proven invaluable in reliable integration of a large amount of wind and distributed solar PV energy. (See Hawai'i Electric Light's Generation Flexibility Plan, Exhibit 11 of the April 2014 Filing PSP for details.) In the analysis performed subsequent to the April 2014 filing, and identified as necessary measures in that filing, security and reliability studies identified the need for increasing regulating and contingency reserve requirements of reliable operation of the power system with increasing levels of DG-PV. As part of the preferred plan, energy storage will be added to the mix of resources to provide some of the system flexibility and resiliency in the future.

Similar to the Maui system, which also has large variable energy sources, Hawai'i Electric Light has implemented many changes in our generation fleet and operation of the assets to increase flexibility and renewable acceptance.

- Retirement of Shipman plant.
- Lowering of the minimums on Hill 5, Hill 6 and Puna steam.
- Increasing ramp rate and primary frequency response for Hill 5, Hill 6 and Puna.
- Variable regulating reserve requirements based on real-time observation of variability and incorporating the variable solar and wind forecast uncertainty band.
- Implementation of centrally controlled curtailment for larger distributed solar and FIT projects.
- Addition of remote control curtailment for the Wailuku River Hydro project.
- Reduction in number of units continuously operating for system security.

On/Off Cycling

The results of past security analysis produced minimum criteria for system reliability for generation units. With that information, units not necessary for system security and reliability are subject to economic unit commitment dispatch, with consideration of the incurred daily cycling costs. The present system operation at Hawaiʻi Electric Light incorporates routine daily cycling of the Hamakua Energy Partners (HEP) combined–cycle plant. Puna Steam is currently cycled on a seasonal basis: left offline with preservation measures for extended periods and brought back on line when needed to ensure adequate capacity. However, based on the present low cost of its fuel, Puna can economically serve demand and will be utilized to serve demand. As shown in the preferred plan, and discussed in the retirement plan, large fossil units are assumed to be displaced by appropriately designed renewable energy and become subject to cycling, layup or retirement.

There have been occasional adequacy of supply issues created through increasing offline cycling. The present operation represents a significant reduction in the number of fossil generation units historically operated and relies more upon cycling. There has been some reliability impact from the increased cycling of generating units, due to the increased potential for shortfall due to delay in startup or startup failure, and reduction of capacity available within two hours or less by putting Puna steam into layup. The commitment of generation has been complicated by the large amount of variable energy from wind and solar, the later which continues to increase. To facilitate operation, state-of-the art forecasting tools have been integrated into the control room. However there remains a great deal of uncertainty in the forecast, which can lead to under- or over-committing the generation. Under-committing occurs when production is lower or a down-ramp occurs, and may lead to a generation shortfall and need for supplemental or emergency generation.

Expanded Turn Down Range

Hawaiʻi Electric Light improved the turndown of its steam units to lower loads. Minimum dispatch limits decreased by 3 MW to 5 MW for Hill 5, and 7 MW to 8 MW for Hill 6, respectively, since mid-2012. The minimum turndown for Puna Steam was also reduced significantly to 6 MW. A new burner tip has been installed in Hill 5 and is being tested as allowing an additional reduction by 1 MW in minimum load. . The minimum economic dispatch limits for other significant units are 27 MW for Puna Geothermal, and 10 MW for Keahole in single-train (combined cycle), the same limit applies for HEP in single-train (which is subject to offline cycling). The regulation limit is 5 MW lower for Puna Geothermal Unit and 1 MW lower for the combined cycle units. H

Fast-Start Resources

Existing generation resources provide a significant amount of fast-start, fast-ramping capability. The resources consist of small diesel units and simple cycle gas turbines

For supplemental and emergency purposes, including to cover for forecast errors, Hawai'i Electric Light has available 46.3 MW that can be started in 20 minutes or less, and 29.5 MW from small diesel units that can be brought online in 2.5 minutes or less. These units are increasingly used to cover for start-failure of cycled units and short-term generation needs caused by forecast error. The availability of these units allows the operator to adjust generation quickly in response to changes in net demand. They are also used to restore under frequency load-shed.

The existing available capacity for fast-start resources is sufficient to meet the supplemental reserve requirements for the Preferred Plan.

Frequency Response, Regulation, and Ramp Rates

Generators and technologies differ in their ability to contribute to essential grid services. Tables providing a summary of technical and operational attributes of existing and potential future resources were provided in the April 2014 Power Supply Plan. In order to best meet system needs for frequency response, regulation, and ramping, new generation additions are required to provide these capabilities to maintain system security and reliability. Moreover, where possible, ramping and regulation capabilities are being improved from existing resources. As part of continuous improvement initiatives, ramp rates were increased for all the steam units respectively, since mid-2012. Increased dispatch range also improves regulation capabilities by allowing a larger contribution of a generator to both up and down reserve. Additional projects to continue to improve generation flexibility can be found in the Power Supply Plan[5].

As part of its expansion to 38 MW, Puna Geothermal Ventures (PGV) changed its facility characteristics from a passive energy source to one that provides frequency response, voltage response, and dispatch under Automatic Generation Control (AGC). PGV can now contribute to primary frequency response, though at this date the range of the response has been limited both because of controls issues and because the facility has been derated since Tropical Storm Iselle. Hawai'i Electric Light plans to continue working with Puna Geothermal in increasing its operational flexibility, following its restoration to 34.5 MW capacity and higher. In the Preferred Plan, the evaluation of new firm capacity renewable resources assumed these resources would provide the grid services comparable to similarly sized conventional plants. Of particular importance in

[5] Refer to "Future Projects (Exhibit 11B)" of the Power Supply Plan that Hawai'i Electric Light filed with the Commission on April 21, 2014.

achieving 100% RE is a resource that can provide the system reliability requirements presently met by the generating units at Keahole Power Plant, through provision of similar operational and technical capabilities and a location electrically near to Keahole, to support East-West power flows and voltages without requiring significant transmission infrastructure. Future new utility-scale variable generation such as the wind plants included in the Preferred Plan will also be designed to incorporate technical and operational capabilities available in present day wind plants, including inertial response, ramp rate control, frequency response, active power control, and disturbance ride-through to contribute to grid operational requirements, mitigate impacts of the variability, and lesson the need for other resources to provide such services.

Due to the impacts of DG-PV, increased contingency response (that is, fast frequency-responding reserves) as well as fast-ramping regulating reserves are required, in addition to ride-through capabilities from DG-PV To meet these needs, an energy storage system with response capabilities in excess of generation capabilities will be added to the system to provide contingency reserves. To meet the faster ramping capabilities, the fast ramp capabilities of the existing combustion turbines will be leveraged.

MUST-RUN GENERATION REDUCTION PLAN

Hawaiian Electric

Integrating renewables into our system needs to be accomplished safely and reliably. As discussed earlier, improving the flexibility of the generating fleet is an important piece to integrating larger amounts of variable resources. Maintaining system security is also very important because without it, the ability of the system to withstand sudden disturbances is compromised. System security is maintained by operating the system with sufficient inertia or fast frequency response, or primary frequency response, limiting the magnitude of the contingency event, maintaining adequate contingency reserves and maintaining system fault current; at times requiring the system operator to sacrifice efficiency for reliability.

The approach taken in this PSIP update was to define and determine the amount of technology-neutral ancillary services for meeting reliability criteria instead of relying on must run generating units. This allows other resources to be used to provide the necessary ancillary services to make the system secure if them meet the requirement defined by the analyses. Demand Response programs, Distributed Energy Resources, and fast frequency response storage technologies could be used to provide the ancillary services and would displace the need to run firm generating units which would provide headroom for more renewables on the system. Synchronous condensers will also be used to provide the required system fault current to operate protective relays on the system instead of requiring generating units to be run. Together, this will reduce the system requirement for requiring generating units to be run to make the system safe and reliable.

Hawaiʻi Electric Light and Maui Electric

We are committed to providing our customers safe and reliable power at all times. To accomplish this, system security and stability is our first priority. A combination of firm generating resources and resources that provide system reserves will ensure that the system demand is met. As we have incorporated significant amounts of variable renewable energy on our system, system security requirements have changed, prompting adjustment in the operation of existing resources. Our system security needs will continue to evolve with our generation resource mix as we continue to increase our renewable energy portfolio.

For system security and reliability, previous system security analysis has identified present minimum must-run security generation, with which the system can generally operate with acceptable reliability.

The selection of resources to meet this constraint is based upon economics. It is probable that firm dispatchable renewable energy, to the extent that is available and cost-effective, can in the future provide all the must-run unit requirements and maintain acceptable system security and reliability.

It is theoretically feasible to remove some or all fossil must-run generation prior to the dispatchable renewable energy resources by utilizing alternative resources. This may enable reduction in generation use, which, depending upon the cost of replacement resources and other tools used to operate the system, can be evaluated for cost effectiveness. Additional analysis based on planning criteria will be performed to identify additional system security constraints beyond the PSIP, which may identify additional resource needs, and/or operational constraints for reduced must-run generators. Prior to altering operational requirements based on system security, the system operators will be provided with resources and operating criteria to ensure acceptable system security based on the through planning analysis. New resources for system security and reliability must go through an operational proving to ensure the performance meets the objectives.

ENVIRONMENTAL COMPLIANCE PLAN

MATS Compliance Strategy[6]

MATS

The MATS rule is applicable only to the steam electric units on Hawaiian Electric's O'ahu system. The MATS rule requires Hawaiian Electric control and measure PM emissions as well as fuel moisture content as surrogates for reducing hazardous air pollutants, including heavy metals and acid gases, from its oil-fired steam generating units by April 2016[8]. The EPA's MATS originally required Hawaiian Electric to reduce emissions of HAPs, including heavy metals and acid gases, from its oil-fired steam generating units by April 2015. On November 6, 2013, Hawaiian Electric obtained from the State DOH a one-year extension on the April 2015 compliance date[7], and now has until April 16, 2016, to comply with MATS.[8] To be ready for the April 2016 compliance date, Hawaiian Electric conducted emissions testing for each steam unit on O'ahu that is subject to the MATS PM emission standard. Tests involved measuring PM emissions to confirm the effectiveness and repeatability of potential MATS solutions. Testing throughout 2014 and 2015 allowed Hawaiian Electric to collect data in order to confirm the accuracy of the MATS solution chosen. As announced in the Companies' January 2016 Update of Fuels Master Plan (FMP)[9], Hawaiian Electric's preferred compliance solution was to utilize a 70/30 blend of Low Sulphur Fuel Oil (LSFO) and diesel at Kahe units 5 and 6, but to continue using 100% LSFO at Kahe units 1-4 and Waiau units 3-8. Subsequent to the issuance of the January 2016 FMP, additional testing on Kahe units 5 and 6 demonstrated that the units can meet MATS requirements using 100% LSFO. This is a departure from Hawaiian Electric's initial concern that all units would have to burn a more expensive 70/30 or 60/40 MATS fuel.

Greater detail about Hawaiian Electric's environmental compliance for MATS and NAAQS can be found in Appendix D: Current Generation Portfolios.

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6 Hawaiian Electric was granted a one-year MATS compliance extension, which places the compliance deadline at April 16, 2016. A second one-year extension is available to utilities through an Administrative Order that would be issued by the EPA. Based on the evaluation criteria established by the EPA in a December 16, 2011 Policy Memorandum, the second one-year extension must be based on a system reliability assessment and is considered a much more difficult extension to obtain.

7 The MATS compliance date is set forth in Title 40 of the Code of Federal Regulations (CFR), Part 63, Subpart UUUUU, National Standards for Hazardous Air Pollutants: Coal-and Oil-fired Electric Utility Steam Generating Units.

8 Only Hawaiian Electric's units are subject to MATS.

9 The FMP is filed semi-annually, currently in Docket No. 2012-0217. It is used to continually update the Commission and other interested parties of the Companies' fuel strategies and procurement timelines.

NAAQS

At this time, NAAQS rules are only expected to impact Hawaiian Electric. In order to demonstrate attainment of the new 1-hour for sulfur dioxide in the vicinity of the Kahe and Waiau Generating Stations, it is unclear at this time whether it will be necessary to reduce the use of LSFO and switch to a lower emissions fuel blend. The best case scenario, absent the use of natural gas, would be utilizing 100% LSFO to comply with NAAQS. The Companies currently believe the worst-case scenario would be blending 40% LSFO with 60% lower sulfur fuel. For planning purposes, the Companies used a conservative approach and assumed the 40/60 blend will be required.

The Clean Air Act (CAA) requires the EPA to set NAAQS for pollutants considered harmful to public health and the environment. The six "criteria" pollutants are carbon monoxide (CO), lead, nitrogen dioxide (NO2), ozone, PM and SO2. The CAA also requires the EPA to review the NAAQS every five years and to revise the NAAQS to reflect the latest scientific information on the impacts of air pollution on public health and the environment. In 2010, the EPA revised the NAAQS for SO2 and NO2 and made them more stringent. Also, the compliance requirements for particles less than 2.5 micrometers in diameter (PM2.5 or "fine particles") were made more stringent. Based on the Companies' preliminary analysis, the new SO2 standard poses the greatest compliance challenge for the Companies. Even though NAAQS potential emission reduction requirements for existing units have been pushed back from the original deadline of 2017, to the 2025 timeframe the Companies had to consider a variety of compliance options for its long-term fuel procurement strategy and planning assumptions. Lowering sulfur emissions to the required levels could be achieved by either switching to a lower sulfur fuel, or by installing air quality control equipment (backend controls).

The Companies believe that the most cost effective way to meet the future NAAQS compliance requirements is to use a fuel that meets the requirements as opposed to installing costly backend controls. To the extent that LNG is lower cost compared to the petroleum-based compliance option, it will result in cost-savings to customers. LNG has emerged as a viable option that will comply with air emission standards, while also substantially lowering fuel costs.

Greenhouse Gas (GHG) Regulations

State of Hawai‘i Act 234 requires a statewide reduction of GHG emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990. The state GHG rules became effective on June 30, 2014, and require all entities that have the potential to emit GHGs in excess of established thresholds to reduce GHG emissions by 16 percent below 2010 baseline emission levels by January 1, 2020. Affected facilities were required to submit an Emissions Reduction Plan (EmRP) to the DOH for approval by June 30, 2015.

Hawaiian Electric, Maui Electric, and Hawai'i Electric Light have a total of eleven facilities affected by the state GHG rule. Together, these facilities account for almost 56 percent of the 2010 baseline emissions from all affected facilities in Hawaii. Hawaiian Electric made use of the partnering provisions in the DOH GHG rule to prepare a single

EmRP that covers all eleven of the Company's affected facilities, and has committed to a 16 percent reduction in GHG emissions company-wide. Hawaiian Electric submitted the Company's EmRP to the DOH on June 30, 2015. Pursuant to the State's GHG rule, the DOH will incorporate the proposed facility-specific GHG emission limits into each facility's covered source permit based on the 2020 levels specified in Hawaiian Electric's approved EmRP.

As part of a negotiated amendment to the Power Purchase Agreement between AES Hawai'i and Hawaiian Electric, Hawaiian Electric has agreed to include the AES Hawai'i coal-fired power plant on O'ahu as a partner in the Company's EmRP. Similarly, with the planned acquisition of the HEP facility by Hawai'i Electric Light, the GHG emissions from the HEP facility will also be addressed in the Company's EmRP. Both the AES PPA amendment and the HEP acquisition are subject to PUC approval so the inclusion of these facilities in the Company's EmRP is also subject to PUC approval. Hawaiian Electric is working closely with the DOH on the timing of the EmRP modifications to address these changes in the partnership

As part of the President's Climate Action Plan, the EPA was directed to adopt GHG emission limits for new and existing EGUs. The EPA issued the final federal rule for GHG emission reductions from existing electric generating units, also known as the Clean Power Plan, on August 3, 2015. The Clean Power Plan set interim state-wide emissions limits for existing EGUs operating in the 48 contiguous states that must be met on average from 2022 through 2029; final limits will apply from 2030. On February 9, 2016, however, the U.S. Supreme Court granted a stay of the Clean Power Plan pending resolution of several challenges to the rule until several petitions for review in the U.S. Court of Appeals for the D.C. Circuit Court can be heard and a decision is rendered.

The final Clean Power Plan did not set forth guidelines for Alaska, Hawaii, Puerto Rico, or Guam because the Best System of Emission Reduction established for the contiguous states is not appropriate for these locations. The EPA indicated its intent to work with the governments for Alaska, Hawai'i, Puerto Rico, and Guam to gather additional information on emissions reduction measures available in these jurisdictions, particularly with respect to renewable generation. However, given the recent Supreme Court decision and pending further action by EPA and federal courts, the timing for establishing federal

GHG emission reduction requirements that may affect Hawaiian Electric's power plants is uncertain.

316(b) Fish Protection Regulations

Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with once-through cooling water systems ensure that the location, design, construction, and capacity of the systems reflect the best technology available to minimize harmful impacts on the environment. Most impacts are to early life stages of fish and shellfish that become pinned against cooling water intake structures (impingement) and are drawn into cooling water systems and affected by heat, chemicals, or physical stress (entrainment).

The EPA issued the final 316(b) fish protection rule on May 19, 2014. This rule titled, *Final Regulation to Establish Requirements for Cooling Water Intake Structures at Existing Facilities*, applies to Hawaiian Electric's Honolulu, Kahe, and Waiau steam electric generating stations. The Kahe and Waiau facilities are required to comply with the impingement and entrainment standards. The Honolulu facility, due to its lower actual intake water flow when operating, may only have to comply with the impingement standard. Honolulu is currently deactivated and will only be required to comply with the 316(b) fish protection rule when it is reactivated.

The final regulation does not specify the best technology available (BTA) standard for entrainment, but states that "the Director must establish BTA standards for entrainment for each intake on a site-specific basis." [§125.94(d), Page 538] In Hawai'i, the "Director" is the Director of the Hawai'i DOH.

Significant studies at Kahe and Waiau need to be completed before the DOH can make a final determination of the technology requirements for the affected facilities. Six years of impingement and entrainment data have been collected at Kahe and Waiau and will be used to complete the required studies for these facilities. A preliminary review of the data indicates that closed-cycle cooling (CCC) or cylindrical wedgewire screens will not be required to comply with the 316(b) rule, but fish friendly traveling screens and fish return systems may be required.

No firm deadline for compliance is specified in the final rule; facility-specific compliance schedules will be developed based upon the results of the required studies, in consultation with DOH, and in coordination with the facilities' NPDES permit cycles.

NPDES compliance also impacts Maui Electric's Kahului Power Plant (KPP). As discussed in the Fossil Generation Retirement Plan, Maui Electric plans to retire KPP's generating units no later than November 30, 2024 in accordance with the compliance plan as approved by the DOH in July 2015.

KEY GENERATOR UTILIZATION PLAN

This discussion recognizes the unique economic and operational challenges that exist for key O‘ahu and Maui generating units.

AES Hawai‘i (AES)

AES is a 180 MW coal-fired power plant serving O‘ahu. The existing Power Purchase Agreement (PPA) between AES and Hawaiian Electric expires on September 1, 2022. The PSIPs assume that the AES PPA is not renewed as of its expiration date.

Kalaeloa Energy Partners (KPLP)

KPLP is a combined-cycle combustion turbine generator that currently operates on LSFO. The Power Purchase Agreement (PPA) between KPLP and Hawaiian Electric will expire on May 23, 2016. As shown in its Adequacy of Supply report filed April 11, 2014, in the absence of new capacity, Hawaiian Electric needs KPLP’s capacity of 208 MW to meet the generating system reliability guideline. In the absence of KPLP, it is estimated that there would be a reserve capacity shortfall of about 175 MW.

Hawaiian Electric is currently negotiating in good faith with KPLP for an extension to the PPA for six years, to approximately 2022. Among the terms being negotiated are: (1) the term of the extension; (2) fuel flexibility including LNG; and (3) operational flexibility including increased turndown to lower loads and extended simple-cycle operation. KPLP has represented that it needs to invest substantial capital to address equipment deterioration, so that it would be able to operate at high levels of reliability beyond the term of the existing PPA, and this is being considered in the negotiations.

At an appropriate price and with appropriate operate operating flexibility, KPLP represents a viable future generator for the O‘ahu power system, especially if it converts to LNG. Unfortunately, the KPLP facility does not have adequate space for LNG storage or regasification. Accordingly, Hawaiian Electric is considering installing such facilities at its property that abuts the KPLP facility, and the possibility of providing natural gas to KPLP from these facilities. Any final agreement would be reflected in an amendment to the PPA that would be submitted for Commission review and approval.

The KPLP facility is expected to be a viable generator in 2022 after the expiration of the potential six-year extension to its PPA, and would be a candidate for a new PPA in the succeeding time period. Because KPLP is an IPP, it is impossible to identify its value in the future without a finalized contract identifying pricing, operating flexibility, and other parameters.

Campbell Industrial Park Combustion Turbine No. 1 (CIP CT-1)

CIP CT-1 is a combustion turbine that currently operates firing biodiesel and is the type of generating unit that is compatible and complementary on a power system with increasing amounts of variable renewable generation. CIP CT-1 provides offline reserve, online spinning reserve, and can be turned on and synchronized to the grid within 22 minutes. It can also be readily turned off in order to accept more variable renewable generation onto the grid. When operating, it contributes a relatively high level of system inertia, can help manage system frequency by responding to minute-to-minute load demand control signals, and can ramp up rapidly to offset rapid down ramps of variable renewable generation.

The fuel efficiency of CIP CT-1 is lower than the AES and KPLP units. For example, at maximum load, its fuel efficiency is about 11,700 Btu/kWh-net. Kahe 6 has a fuel efficiency of about 10,050 Btu/kWh-net at full load. In combination with the higher cost of biodiesel compared to LSFO, CIP CT-1 is the highest cost generator on the O‘ahu power system.

Once the Schofield Generating Station (SGS) is in service first quarter of 2018, CIP CT-1 will switch to using diesel as its normal operating fuel. The biodiesel that would have otherwise been used at CIP CT-1 will subsequently be used in the new SGS engines. Pacific Biodiesel supplies the biodiesel currently used in CIP CT-1 via a contract that has a minimum purchase amount of 2 million gallons per year. This contract expires in November 2017. Whether operated on diesel or biodiesel, CIP CT-1 represents a vital resource for the O‘ahu system due to its operating characteristics. The frequency with which CIP CT-1 is operated will depend on its relative fuel cost and system conditions.

Other Generating Units Owned and Operated by Hawaiian Electric

In order to reduce costs to customers, Hawaiian Electric is pursuing the use of LNG in a new 383 MW 3 x 1 combined cycle plant to be constructed at the Kahe site. If approved, the new Kahe combined cycle plant would enter service in 2021.

Use of and retirements of existing generation depends ultimately on the plan that is approved. Unit retirement plans are described in Hawaiian Electric’s Plan for Retiring Fossil Generation.

Role of Thermal Generation in the Future

With a mandate for 100% RPS by 2045, we envision declining utilization of thermal generating units that are oil fired. Thermal generation is however desirable, to accommodate cleaner and less price volatile LNG and / or to provide strategic use of liquid biofuels that allow the thermal units to "back up" the variable renewable energy and energy storage systems in those situations when there is no alternative to meet system demand other than by relying on the thermal generation fleet.

Maui Electric Key Generation Units

The units listed below provide benefits to the Maui system that include system security, minimized costs through efficiency and low cost LNG fuel, or flexibility.

- Dual-Train Combined Cycle units: high efficiency, low LNG fuel cost, provides regulating reserves, provides contingency reserves.
- Combustion Turbines: low LNG fuel costs, operational flexibility through startup availability and dispatch.
- Small diesel internal combustion engines (MX1, MX2, M1, M2, M3): quick-starting

Large diesel internal combustion engines (M10, M11, M12, M13): operational flexibility through startup availability and dispatch. It is also anticipated that the small and mid-size diesel units will be operated very infrequently, as they will be designated to operate during peak load periods or when variable renewable resources are unavailable.

Hawai'i Electric Light Key Generation Units

The Puna Geothermal Venture facility provides firm capacity renewable energy, and will continue to be a significant resource towards renewable energy goals for the foreseeable future.

The dual train combined cycle units at Keahole and HEP provide benefits that include system security, fuel efficiency, and fuel flexibility. Conversion to LNG offers potential to stabilize costs associated with oil. These resources have flexible operational characteristics, can cycle offline, and will continue to be used to economically serve demand.

The steam units provide excellent system stability and primary frequency response, and with the present modifications, good dispatch range ad ramping capability. The minimum dispatch limit (in MW) is lower than combined cycle units. The three steam units are presently the lowest cost resources to serve demand due to the low cost of IFO fuel, and are being leveraged to economically serve demand now and for the near term, assuming the fuel costs remain such that these remain lower cost than alternate available resources. However, the units are inefficient and not expected to remain cost-competitive under scenarios of higher fuel costs, and are not candidates for switching to more expensive renewable energy fuels and assumed to be candidates for decreased operation or retirement with the addition of renewable resources.

The fast-start diesels and simple cycle combustion turbines, which have played a large part in the integration of the present high levels of variable renewable energy and support the amount of off-line cycling and low online reserves of today, will continue to play important roles in providing fast replacement reserves and supplemental reserves for forecast errors, ramping events, forced outages (including failed start) and other short term and emergency energy needs.

OPTIMAL RENEWABLE ENERGY PORTFOLIO PLAN

Hawaiian Electric's Renewable Energy Portfolio Plan

Hawaiian Electric's optimized plan is described in Chapter 5.

Hawai'i Electric Light's Renewable Energy Portfolio Plan

Hawai'i Electric Light's optimized plan is described in Chapter 7.

Maui Electric's Renewable Energy Portfolio Plan

Maui Electric's optimized plan is described in Chapter 6.

GENERATION COMMITMENT AND ECONOMIC DISPATCH REVIEW

The Generation Commitment and Economic Dispatch Reviews are similar for all three operating utilities.

Prudent Dispatch and Operational Practices

Our unit commitment and economic dispatch policies are based on safe and reliable operation of the system, minimizing operating costs, and complying with contractual and regulatory obligations. The daily generation dispatch process is illustrated in Figure M-1.

With increasing amounts of distributed solar, large amounts of wind power, and increased offline cycling, state-of-the art forecasting tools have been integrated into the control room. These tools are used to inform unit commitment decisions with forecast power production, variability, and indication of uncertainty in the forecast. However there remains a great deal of uncertainty in the forecast, which can lead to under- or over-committing the generation. Under-committing occurs when production is lower or a down-ramp occurs, and may lead to a generation shortfall and need for supplemental or emergency generation.

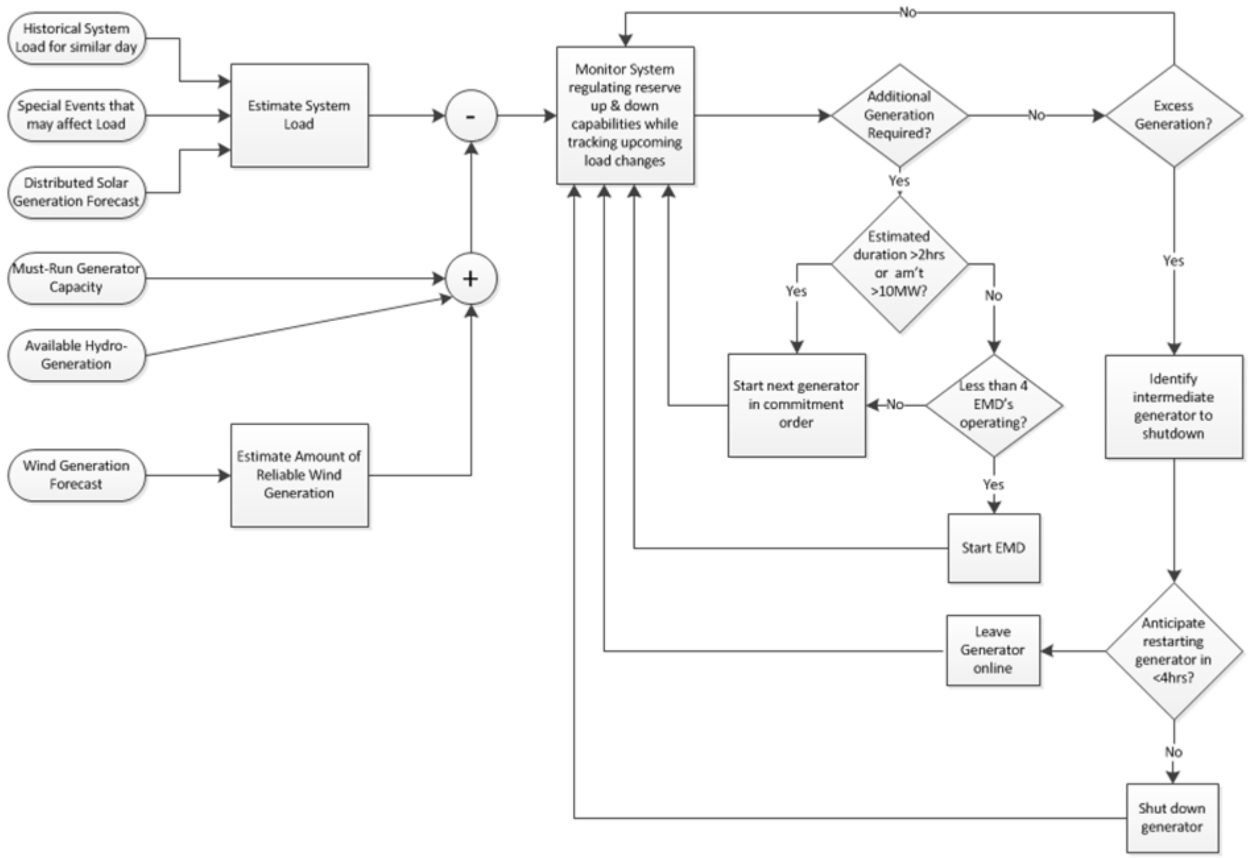

Figure M-1. Daily Generation Dispatch Process

Maui Electric and Hawai'i Electric Light have integrated its state-of-the art wind and PV forecasting into the control room, which is used for the daily unit commitment decisions. The amount of online reserves carried is adapted in real-time based on upon the observed variability of the net demand, primarily driven by wind and solar. Unit commitment and economic dispatch are based on economic dispatch, subject to the security constraints, PGV contract levels, unit limits, and must-take energy. A factor in unit commitment is the duration of the load to be served. With the increase in DG-PV, a shorter day peak occurs during which it may be more economic to startup a faster-starting but less-efficient resource such as a simple cycle turbine. Maui Electric also has to factor in reactivation of its deactivated units based on capacity and transmission planning requirements to meet daily peak load and 23kV line voltage support.

Additional projects are being developed which will further integrate the forecasting and services and visualization into the EMS and provide additional visibility and control of distributed energy resources. In the future, the unit commitment decisions will incorporate net-demand forecasts, which include the forecast wind and solar production and demand response options. For supplemental frequency control and reserves new resources will be integrated into the EMS, including storage, demand response, and response capabilities from variable resources.

Minimization of Ancillary Services Costs

The process to identify system security constraints, and the combinations of resources which can be used to meet them, is summarized as follows:

- Determine system constraints.
- Identify the resource mix that meets each of them.
- Select the lowest cost combination of resources to operate.

For all three operating utilities, additional security constraints are imposed with increased concentrations of variable renewable resources. Therefore, the projected increase in DG-PV may have an impact on ancillary service costs. We will continually evaluate the economics of using existing resources to meet ancillary service and system security requirements versus meeting those needs with alternative resources including energy storage and demand response.

Maximizing the Use of Available Renewable Energy

The commitment and dispatch of renewable energy resources depends upon the contract terms for those resources and whether or not the system operator has visibility and control over the generation. If the resource can be economically dispatched, it is put under automatic generation control (AGC), and its output is determined by its marginal cost relative to the marginal cost of other resources. Examples of this type of renewable resource includes geothermal, generating units using renewable biofuels, waste-to-energy projects, and other "firm" renewable projects. In the PSIP plans, the value of dispatchable renewable energy has been identified as providing value by displacing maximum amount of fossil fuels through the high capacity factor. However, these types of resources are not available on Oahu, unless procured through interconnection to other islands.

Variable renewable energy projects have been contractually treated as must-take, variable energy. These are accepted regardless of cost, but their output is reduced as needed when all intermediate units are offline and there remains excess energy production. In this case, the system operator curtails the output of variable energy providers to the degree necessary to keep the system in balance and provide response reserves. Most curtailments are partial—the output is limited, but the resource is not restricted to zero output. When excess energy necessitates curtailment, it is performed in a manner consistent with the purchased power agreements associated with the affected resources and in accordance with a priority order established by the system operator.

In addition to excess energy situations, curtailments can also be required for system constraints such as line loading, phase angle separation, line maintenance, and frequency impact from power fluctuations. Curtailments for system constraints are applied to the resources as needed to address these constraints and are not subject to the priority order used for excess energy curtailments. Curtailments are also performed at the request of wind plants for wind conditions, and equipment issues.

The vast majority of DG-PV is not visible or controllable by the system operator. These resources serve demand ahead of all other resources. Additional growth in DG-PV is forecast to cause increased curtailments of utility-scale variable renewable resources, unless DG-PV is required to provide the visibility and control to the system operator.

As the islands evolve to every increasing levels of renewable energy, the ability to treat any type of energy as "must take" is increasingly limited in the absence of storage. The islands serve only the demand on the island systems and cannot export excess production as is done in other interconnected areas. Accommodating the renewable resources will displace existing generation that provided dispatchable energy, adjusted to meet demand, and many other characteristics to keep the power system stable and operable. These capabilities to adjust output to serve demand, respond to frequency, regulate voltage, etc. will be increasing relied upon from variable resources and firm renewable resources as the systems are transformed to economically and reliably serve the energy needs of the future with 100% renewable energy. This increasing contribution to grid management will require changes to both procurement terms and technical and operational capabilities of all renewable resources, including distributed energy resources.

Energy Management Systems (EMS)

The operation of the system is facilitated by use of a centralized Energy Management System (EMS). The EMS provides the system operator with constantly updated, real-time information about the operational state of the system. There are three key program applications within the EMS:

- Supervisory Control and Data Acquisition (SCADA)
- Real-time Automatic Generation Control (AGC)
- Real-time State Estimator

Currently, Molokaʻi and Lanaʻi do not have AGC capability due to their small size, and rely upon isochronous control units for frequency regulation.

All three Companies routinely update the EMS hardware and software platforms for each system in order to ensure reliable operation, to incorporate new industry developments such as protocols and system security measures, and to maintain support from EMS vendors.[10] With the transformation of the utility systems additional interfaces are required to the EMS for control of distributed generation, new types of resources such as storage, demand response integration, and variable generators which have varying levels of reserve depending upon set point and available resource. This will require modifications to the interface, new controls, and modeling of the resources within AGC.

To accommodate the migration to smart-grid network and integration of new resources and the use of the communications protocols to support this, the companies are hardening the security of their EMS systems. Hawai'i Electric Light has tested MPLS communication to a remote terminal unit from a secured EMS network.

Additional applications are being developed to facility with dispatch decisions and system management with the changing resource mix. AS one example, in 2016 an adaptive underfrequency load-shed application will be integrated in the Hawai'i Electric Light system to assign circuits to underfrequency load-shed tiers in real-time, reflecting the telemetered demand on each circuit and total load-shed quantity needed at the time.

System Dispatch and Unit Commitment

Unit commitment and dispatch decisions are based upon:

Safety. Our dispatch of generating resources is always subject to ensuring the safety of personnel and the general public.

Reliability. Dispatch and unit commitment must adhere to system security and generation adequacy requirements.

Contractual Requirements. Dispatch and unit commitment must adhere to contractual constraints.

Cost. After meeting all the forgoing requirements, we commit units and dispatches units based on their marginal cost, with lower cost units being committed and operated before higher cost units.

When determining the unit commitment and dispatch of generating units, we do not differentiate between dispatchable IPPs and utility-owned assets. The daily unit commitment modeling tool input date does not differentiate units by ownership. Certain generators do receive a form of priority in terms of energy being accepted onto the

[10] We operate EMS systems from two different vendors, *Alstom* at Hawai'i Electric Light and Maui Electric, and *Siemens* at Hawaiian Electric.

system on the basis of the location of the generator, its characteristics, or the contractual obligations unique to the resource. The acceptance of energy is in the following order of preference:

Distributed Generation: Distributed generation resources receive preferential treatment as "must take" resources regardless of their economic merit for system dispatch. At the present time, we have no control over, or ability to curtail, distributed generation.

Scheduled Contractually Obligated Generation: These resources are preferentially treated from a dispatch perspective by contract. They are used to serve customer load regardless of their economic merit for system dispatch. Scheduled energy from these resources is taken after distributed generation, but ahead of all other resources including variable energy providers.

Contractually Must-Run, Dispatchable Generation: The resources cannot be cycled offline and therefore the minimum dispatch level of these resources are preferentially treated in the system dispatch determination and the energy is accepted from these resources regardless of cost, except during periods of maintenance.

Generation to Meet System Security Constraints: These resources provide energy at least at their minimum dispatch limit, ahead of other resources, similar to contractual must-run and scheduled generation, plus an amount of reserve capability to provide down regulation. However, once dispatched, the continued operating status of these resources is subject to continual evaluation of their costs relative to other alternative resources that may become available at a lower cost, except where it is required by contract.

Variable Energy: Variable energy is accepted on the system, regardless of cost, after distributed generation, scheduled energy purchases, and continuously operated generation. This energy is accepted regardless of cost and thus presents a constraint on optimized (lowest) cost. If the energy cannot be accommodated due to low demand, curtailment of the resource is ordered according to an established and approved priority order. As discussed above, variable energy will increasingly be treated as dispatchable and contribute to grid management. This will require additional EMS interfaces.

Dispatchable Resources: Energy from dispatchable resources is taken on the basis of relative cost (economic dispatch). Resources with the lowest variable energy (fuel and O&M) cost will be committed ahead of resources with higher variable costs. Online resources with lower incremental costs will be dispatched at higher outputs ahead of resources with higher incremental costs. The units operated routinely to meet demand, but cycled offline during minimum demand periods, are described as intermediate units. Short-term (daily) unit commitment decisions do not consider fixed costs associated with these resources because the fixed costs will be incurred regardless of whether or not the unit is operated.

Compliance: Permit restrictions or requirements may affect the operation of generation units

Generator Availability: Generators may be out of service for planned maintenance or unplanned reasons

Transmission Constraints: Transmission and distribution maintenance plans

As-available Forecasts: Operational decisions may be different based on wind and solar forecasts versus perfect knowledge of the resource

Weather: Conditions or other risk conditions may require adjustment of the generation mix to provide additional security margin

Distributed Energy Resources: At present, visibility and control of distributed energy resources is limited to only larger sites and FIT projects. As with utility scale variable generation, DER will be increasing integrated into the EMS, including monitoring and control capabilities. Adaptive Underfrequency Load-shedding: This new application is being developed to enable effective load shed protection schemes under high DG-PV penetration. With increasing amounts of self-generation, the available demand for underfrequency load-shed on each circuit is highly variable ad dependent upon solar PV production. The amount of load that must be shed is dependent upon net system demand and contingencies. As mentioned above, the EMS is being adapted at Hawai‘i Electric Light in 2016 to assign circuits to the load shed scheme stages dynamically, based on telemetered available circuit demand and the total system net demand.

Utilization of Energy Storage and Demand Response

Energy storage and demand response (DR) programs can provide the system operator with a flexible resource capable of providing capacity and ancillary services. To provide the system operator with appropriate control and visibility, energy storage assets are equipped with essentially the same telemetry and controls necessary to operate generating units. DR used for providing regulating reserves and contingency reserves is also equipped with appropriate telemetry and controls. The specific interface requirements depend upon whether the storage device or demand response resource is responding automatically, or is under the control of the system operator. DRMS and ESMS is interfaced with or directly incorporated in an EMS. For storage or demand response that is integrated into the EMS, telemetry requirements include:

- For storage, real-time telemetry indicating charging state, amount of energy being produced, device status.

- Control interface to the EMS to enable the increase and decrease of energy output from the storage asset, and for energy input to the storage device for charging.
- For demand response, real-time telemetry indicating breaker status, switch status, and load.
- Control interface to the EMS to enable the triggering of load shed in response to automatic signals (for example, underfrequency) or a command from the system operator.

Depending on the specific application, storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve. Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource in order to provide "smoothing" of the renewable resource output.

A special consideration of short-duration storage is the fact that it is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset's charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources prior to depletion of the storage. This replacement could be in the form of longer-term storage or generation resources. In order for the value of the demand response to be realized in providing a particular grid service, once called, the load cannot return to the system until after a specified time, which is dependent on the type of grid service being provided by the demand response resource. Accordingly, the system operator similarly requires information regarding the status of demand response, particularly as it relates to the state of the response after an event has been triggered.

Visibility and Transparency in System Dispatch

A high level review of the Renewable Watch websites of various ISOs including PJM, MISO, Cal ISO, and ERCOT, shows the following operational information commonly being displayed, along with ISO energy market-specific information such as locational marginal pricing:

- Real time daily demand curve showing actual and forecasted demand, updated at least hourly
- Hourly wind power MW or MWh being produced and forecasted
- Other renewable energy production in MW (California)
- Available generation resources

Our Renewable Watch site currently displays the following information, with data updated approximately every 30 minutes:

Net Energy System Load. The system load served by generators on the "utility-side" of the meter including those owned by the utility and by independent power producers (IPP).

Gross System Load. The net system load plus estimated load served by the customer side of the meter by DG-PV.

Solar Irradiance Data. This data is measured in different regions of the island, which are used as input to calculating the estimated load served by DG-PV.

Wind Power Production. Total megawatts of wind power being produced by the various IPP-owned wind farms selling electricity to the Companies.

To provide further information to customers about the dispatch of various energy generation resources under the utility's control, we are currently partnering with the Blue Planet Foundation to develop and publicly present real time breakouts of the percentage of net energy system load being served by various fuel types, including coal, oil, wind, waste-to-energy, solar, and biofuel. Hawaiian Electric and Blue Planet believe this information will be useful in raising customer awareness of the use of renewable energy versus fossil fuels. A prototype kiosk was displayed at the Hawai'i Clean Energy Day event on July 22, 2014 with positive public reaction.

In light of this information already being developed for public display, we are agreeable to the following enhancements to our website. The information on the Renewable Energy watch website will be supplemented with additional information showing for the previous hour the percentage of the energy supplied by the different resources (IPPs, Renewables, Company generating units). A historical archive of the percentage of the energy produced by each of the resource groups for the previous 24-hour period will be maintained so that the customer can view the changes over time.

These enhancements will address the Commission's objectives of showing the significant use of non-utility generation and renewable resources, most of which, with the exception of our combustion turbine generation CIP CT-1, which uses biofuels, are IPP owned.

In addition, we also make public a description of its economic dispatch policies and procedures, via posting on its company website. Combined, the enhancements to our website and the sharing of its dispatch policies and procedures will increase visibility and transparency of how generating resources are being dispatched on the power grid.

Our generating unit commitment and dispatch of the generating units is based on the objective of incurring the least cost to the customers while continuing to maintain system reliability. With the introduction of increasing amounts of renewable resources on the systems, it has become more important to minimize the use of fossil fuels and contending with the dynamic system changes that occur from the new resources so that reliability can be maintained. A screenshot from the Renewable Watch–Oʻahu website is shown below in Figure M-2 to provide an example of the variability of the renewable energy resources.

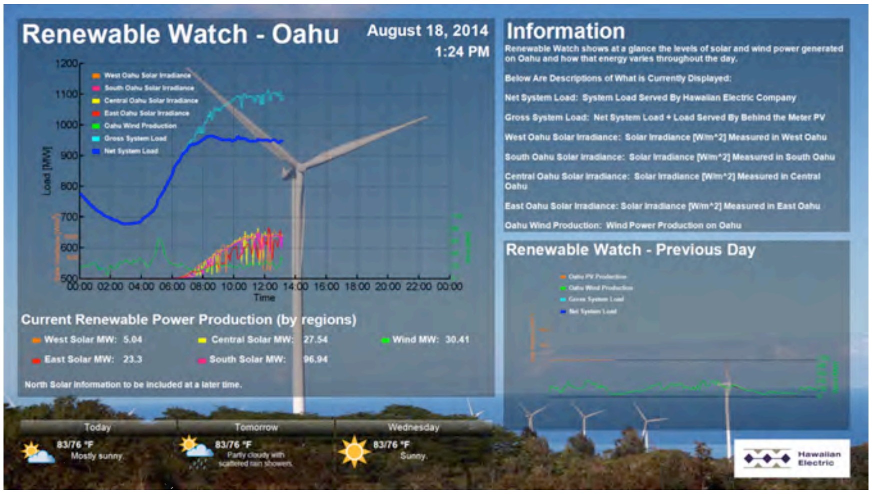

Figure M-2. Renewable Watch–Oʻahu Website Screenshot

Keep in mind that the changes that have been occurring on the all Company respective systems for a few years, but at different rates of change. Maui and Hawaiʻi Island have been changing at a far more rapid pace due to the high availability of renewable resources that could be used on each island.

We understand the importance of visibility and transparency of the economic commitment and economic dispatch to show the customers that a real effort is being made to reduce the use of fossil fuels and to encourage the use of renewable resources. Creating a website with the same information that RTOs or ISOs use to show price of energy for the market may be misleading if the customer is unaware of the system conditions that is dictating how the generating units are being run. The information that is graphically displayed on the existing Renewable Watch websites is a good starting point for creating visibility and transparency.

We are working with Blue Plant to incorporate additional information displays that include the system load and the percent of power to service load provided by each resource group. We recommend showing this additional information to customers so that they are able to see, over time, that fossil fuel generation is being substituted with less costly generation.

N. Integrating DG-PV on Our Distribution Circuits

Nearly half of our distribution circuits are penetrated with PV past 100% of daytime minimum load—a now ubiquitous part of the distribution grid. Further integration of PV onto the distribution system will require modernization to achieve an advanced distribution system that leverages new technologies to enable customer choice and multidirectional power flow.

This appendix details the methodology, assumptions, and investment strategies available at the distribution circuit level to integrate greater amounts of PV.

Integration costs were developed for two DG-PV cases: the base DG-PV forecast and the high DG-PV forecast. The system-wide forecasts developed for each of the operating companies served as the basis for distributing DG-PV onto the distribution system. Simulations of our distribution system model informed the PV integration cost estimates.

We considered various solutions and strategies leveraging traditional solutions, emerging technologies, and advanced inverter capabilities. The portfolio of strategies and associated costs were then used as an input to the iterative Distributed Energy Resources (DER) cycle as part of the optimization process.

DISTRIBUTED GENERATION INTERCONNECTION PLAN UPDATE

This report is intended to provide an update to the specific strategies to implement circuit upgrades and mitigation measures to interconnect additional distributed generation we filed with the Distributed Generation Interconnection Plan (DGIP).[1]

This update reflects a deeper analysis of the distribution system than was done in the DGIP to more accurately identify the necessary circuit upgrades to integrate higher amounts of PV through field experience in our high DG-PV environment in combination with the advancements we have made in modeling our distribution system. This analysis was facilitated by the completion of models of each of our island distribution systems in late 2015.

Since the DGIP filing in 2014, we have upgraded 64 load tap changer controllers on O'ahu, totaling $380,000, which modernized our voltage regulation equipment to accommodate reverse power flow. We've completed research on ground fault overvoltage and no longer require grounding transformers on the distribution level.[2]

DG-PV Integration Plans and Costs Methodology

The development of integration plans and costs for the two DG-PV forecasts followed a five step process. When DG-PV installations exceed a circuit's hosting capacity,[3] that distribution circuit will likely require upgrades to accommodate the additional DG-PV.

The following method was used to study the integration solutions:

1. Allocate PV forecasts to the distribution circuits
2. Model impact of forecasted PV on distribution system
3. Identify solution options to integrate forecasted PV
4. Quantify integration plans and costs for all solutions
5. Derive integration cost estimates

Each step in the methodology is described below.

[1] Hawaiian Electric Companies filed its Distributed Generation Interconnection Plan on August 26, 2014 to comply with Order No 32053 issued by the Hawai'i Public Utilities Commission on April 28, 2014, in Docket No. 2011-0206.

[2] As discussed later in this appendix, concerns remain with respect to ground fault overvoltage on the sub-transmission (46kV) level. However, the 67 grounding transformers totaling $4.4M at Maui Electric and the 16 grounding transformers totaling $1.1M on Hawai'i Electric Light, as stated in the DGIP, are no longer required in most situations provided PV systems meet the Companies current transient overvoltage standards. See DGIP At 3-6.

[3] The Hawaiian Electric Companies filed its Circuit Level Hosting Capacity analyses on December 11, 2015 in Docket No. 2014-0192. The Hawaiian Electric Companies proposed the PV Circuit Hosting Capacity Analysis method to support their proposal to integrate circuit hosting capacities into the interconnection process. The PV Circuit Hosting Capacity Analysis method identifies the distribution circuit capacity to safely and reliably interconnect Distributed Generation (DG) PV resources.

Step 1: Allocate PV Forecast to the Distribution Circuits

The DG-PV forecasts reflect the overall, or system wide forecasted growth of DG-PV on each island grid for the two DG-PV scenarios. To determine the cost to integrate these total DG-PV levels, the impact to each individual circuit was analyzed. The installation of DG-PV is a customer choice; thus, we cannot predict the exact installation location of future DG-PV at the circuit level. We used a circuit allocation methodology that reflects Hawai‘i’s mature PV market, that is, we assumed PV would grow proportionally into the future and maintain the same relative circuit penetration levels that exist today, with the rationale that the PV industry has identified and penetrated those market segments, neighborhoods and circuits with the resources and market drivers to adopt PV.

The method increased each circuit’s existing PV level year over year by the growth rate determined by the base and high DG-PV forecasts through 2045. A circuit was allowed to grow up to its maximum potential which was determined by estimating the number of single family homes residing on each circuit. The future PV systems were sized to offset that customer’s historical 12 month energy consumption. The maximum potential considered the commercial sector by estimating that 25% of commercial customers on a circuit installed PV. Where Hawai‘i Electric Light and Maui Electric did not have detailed demographic data of a circuit, customer counts and rate class information were used as a proxy to estimate the maximum PV potential of the circuit.

The initial run of integration costs were based on the original system-wide forecasts in Figure N-1 and Figure N-2.

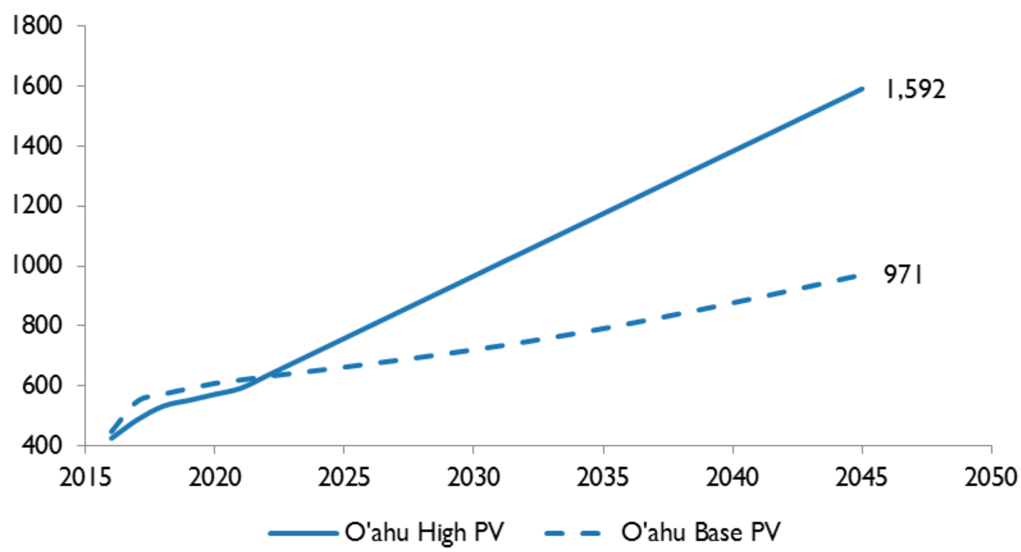

Figure N-1. O‘ahu System-Wide DG-PV Forecast, Base and High Case

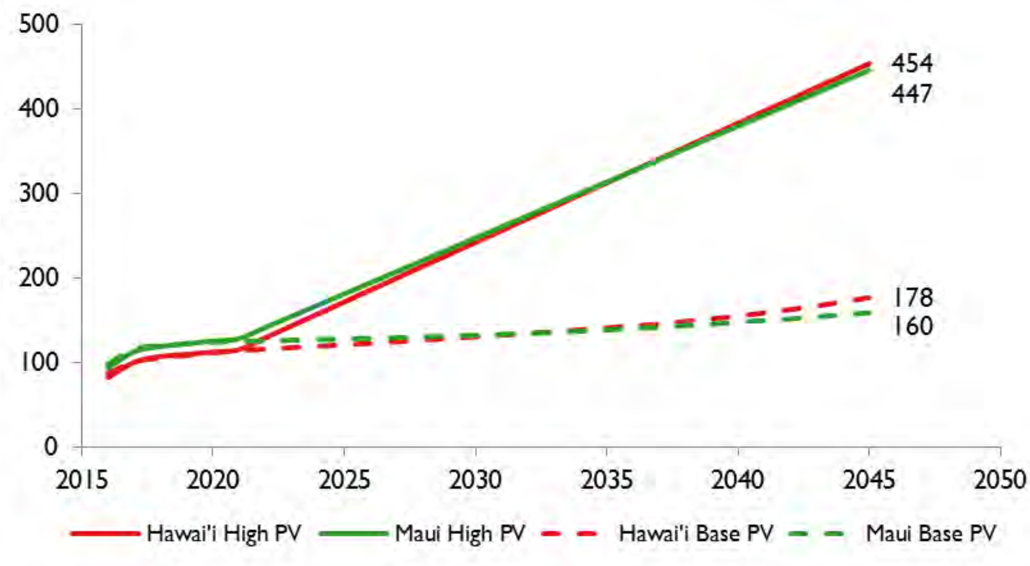

Figure N-2. Maui and Hawai'i Island System-Wide DG-PV Forecast, Base and High Case

A circuit did not receive additional growth after the year in which it reached its maximum PV potential. Not all circuits reached their maximum potential because of current low penetration amounts which reflect neighborhoods with low customer demand for PV. Many currently saturated circuits reached their maximum potential well before 2045.

The PV forecast by circuit is provided in the later section titled, DG-PV Forecast by Distribution Circuit.

Step 2: Modeled Impact of Forecasted PV on Distribution System

The forecasted PV of each circuit was compared to its hosting capacity and operational circuit limit.[4] A circuit forecasted to exceed its hosting capacity was analyzed to determine the cost to integrate the forecasted PV amount. A circuit that did not realize PV growth exceeding its hosting capacity did not incur major circuit upgrades; therefore, an integration cost was not determined for that circuit. Table N-1 and Table N-2 show the number of circuits, for each operating company, that are forecasted to exceed their hosting capacity and operational circuit limit in the base DG-PV case and high DG-PV case.

Base-PV Case	Total Distribution Circuits	Exceeded Hosting Capacity Only	Exceeded Operational Circuit Limit
Hawaiian Electric	416	64	86
Maui Electric	137	44	7
Hawaii Electric Light	135	49	22

Table N-1. Number of Circuits by Company, Forecasted to Exceed Hosting Capacity and Operational Circuit Limit, Base DG-PV Case

High DG-PV Case	Total Distribution Circuits	Exceeded Hosting Capacity Only	Exceeded Operational Circuit Limit
Hawaiian Electric	416	41	160
Maui Electric	137	76	76
Hawaii Electric Light	135	20	94

Table N-2. Number of Circuits by Company, Forecasted to Exceed Hosting Capacity and Operational Circuit Limit, High DG-PV Case.

Three areas were assessed in determining integration costs: thermal capacity, voltage quality, and operational flexibility. The hosting capacity models[5] were used to grow each circuit to its forecasted PV amount. A conductor that exceeded 100% of its thermal rating from the reverse power flow of PV was flagged for mitigation.

Analyzing voltage quality requires a deeper analysis of the hosting capacity models, and analysis results vary by location. Mitigation of unacceptable voltage levels normally requires multiple iterations of load flow simulations. Consequently, a cross section of

[4] The hosting capacity is the level of PV that a circuit may host without requiring upgrades to the primary part of the distribution system. The operational circuit limit defines the reverse power threshold at the substation to maintain the operational flexibility of the circuit. For further discussion, see the "Distributed Energy Resources Planning" section at the end of this appendix.

[5] See "Rooftop PV Interconnections: A Methodology of Determining PV Circuit Hosting Capacity" filed in Docket No. 2014-0192, on December 11, 2015.

representative circuits with their forecasted PV growth amounts were analyzed and analysis results were applied to all distribution circuits. Areas where PV caused voltage to rise more than 2.5% of nominal on the primary were flagged because the circuit models stop at the distribution transformer (primary part of the distribution system). ANSI Standard C84.1, Range A, requires delivery of voltage to customers at ±5% of nominal voltage. Our typical design of the distribution system allows for 2.5% voltage drop/rise between the substation and the distribution transformer (primary side) and 2.5% voltage drop/rise between the distribution transformer and the customer meter, amounting to the delivery of voltage within ±5% of nominal voltage. Localized areas where voltage exceeds this criterion were flagged for mitigation.

Maintaining the flexibility of the distribution system is vital to the reliability and safety of electrical service to our customers. If the forecasted reverse power flow from PV of a circuit exceeds that circuit's operational circuit limit then that circuit was flagged for mitigation.

Step 3: Identify Solution Options to Integrate Forecasted PV

The identification of solutions to resolve thermal capacity, voltage quality, and operational flexibility issues are categorized as traditional "wires" solutions and technology "non-wires" solutions. While many different solutions exist, Table N-3describes the various solution options considered in this analysis. The most cost-effective option was then used in the DER iterative cycles when accounting for integration costs in forecasting DG-PV adoption.

Solution Portfolio		
Issue	*Traditional (Wires)*	*Technology (Non-Wires)*
Thermal Capacity	Overhead and Underground Conductor Upgrade Distribution Transformer Upgrade	Battery Energy Storage
Voltage Quality	Voltage Regulator Installation Distribution Transformer and Secondary Conductor Upgrades	Var Compensation Devices (power electronics, fast switching capacitors, advanced inverters)
Operational Flexibility	Re-Configure Circuit New Circuit and/or Substation Transformer	Battery Energy Storage Advanced Inverter DER Controllability

Table N-3. Portfolio of Solutions to Integrate Forecasted DG-PV Amounts

It is important to draw a distinction between mitigation and optimization solutions. The analysis completed here should be interpreted as necessary upgrades; absent the implementation of these solutions would result in unsustainable DG-PV growth because of the impact it poses to the safety and reliability of the distribution system, including its effect on non-participating customers. Particularly when considering technology solutions, these are deployed to mitigate the impacts of DG-PV and generally are not providing circuit optimization or improved efficiencies, rather maintaining or restoring the integrity of the distribution system.

The following describe in detail each of the solutions in the portfolio.

Overhead and underground conductor upgrade. The generation of excess rooftop PV energy will create reverse power flow that may overload conductors past 100% of their thermal rating. To create additional rated capacity, conductors are upgraded to a larger size. Load flow simulations of the hosting capacity models with PV grown to the forecasted amounts determined with a better degree of accuracy the total length of overloaded conductors in the base and high DG-PV cases. The total length of overloaded conductors by circuit were scheduled for upgrade between the year the PV forecast per circuit exceeded the hosting capacity and ending in the year PV growth stopped. The cost to upgrade overhead conductors including wood pole construction is estimated at

$1,100,000 per mile in 2016$. The cost to upgrade underground conductors including duct bank and manhole installation is estimated at $4,300,000 per mile in 2016$.

Voltage regulator installation. A voltage regulator is a traditional solution that corrects voltage power quality issues, and is installed on circuits where the PV forecast exceeds that circuit's hosting capacity. High and low voltage will be the number one barrier to interconnection in the near-term.

Load flow simulations of representative circuits demonstrated that neighborhoods or sections of circuits may experience high and/or low voltage. Every circuit is unique and will vary in its voltage quality issues. Based on the representative analysis, an assumption was made that up to three voltage regulators per circuit would be required to correct voltage impacts. Each circuit that exceeded its PV hosting capacity incurred a voltage regulator installation for three consecutive years following the year in which its hosting capacity was exceeded, except in the case where PV growth stopped in less than three years. The cost to install a single phase regulator and three phase regulator is estimated at $25,000 and $75,000 respectively, and does not include potential wood pole replacement. For the purposes of this analysis, the unitized cost per voltage regulator installation was estimated at $41,667 in 2016$; the average cost of installing two (2) single phase regulators and one (1) three-phase regulator.

Distribution (service or secondary) transformer replacement. Distribution transformers are deemed overloaded, and therefore upgraded, if the ratio of aggregate PV connected to a transformer to the transformer rating exceeds 200%.[6] In other cases, secondary high voltage will necessitate an upgrade of secondary conductors in addition to the replacement of the distribution transformer.[7] The load flow simulations of the hosting capacity models determined that in the base DG-PV case, 16% of distribution transformers would have a PV penetration (aggregate PV connected to a single transformer divided by transformer rating) in excess of 200%, and 26% in the high DG-PV case. These results were applied to predict the amount of future transformer upgrades required to resolve both loading and voltage issues, which can be mutually exclusive. The average cost for this upgraded is estimated at $13,500, representing the estimated average cost between a transformer upgrade to address overloading and an upgrade to address secondary high voltage. In practice, correction of secondary high voltage may cost more than $13,500, particularly if underground construction is required;

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6 The Companies worked with their distribution transformer manufacturer to determine the appropriate PV penetration level as to not severely impact the life and performance of the transformer. Based upon the results of the manufacturer analysis, it was determined that we would allow 200% PV penetration on a distribution transformer before taking remedial action.

7 Distribution transformer upgrades can be triggered well in advanced of a circuit reaching hosting capacity. Issues related to distribution transformer upgrades were not considered in establishing a circuit's hosting capacity. Whether a distribution transformer upgrade is required is dependent on a set of localized factors.

however for this analysis all service transformer work was assumed to cost $13,500 in 2016$.

Re-configure circuits. The most cost-effective method to resolve the loss of operational flexibility is to re-configure a circuit. Before requiring any type of substation upgrades, planners will analyze the circuits to determine whether a circuit is capable of re-configuration with an intertied circuit. This analysis was not performed in the development of the integration costs except for a few cases; the vast majority of operational circuit limit exceedances were resolved with substation upgrades. As circuits approach these limits in future years, we will always seek to avoid substation upgrades where possible. No capital costs were assigned for this work.

Substation upgrades. Substation upgrades are triggered in two ways: (1) if operational flexibility is lost where reverse power loads the substation transformer more than 50% of its highest transformer rating, or (2) with controllable PV, reverse power flow loads the substation transformer more than 100% of its highest transformer rating. Current operational practice is to maintain operational flexibility during normal operation, and therefore reverse power flow is roughly limited to 50% of its highest rating. However if PV is controllable through the use of advanced inverters, it is possible to allow reverse power flow to load the transformer up to 100% of its thermal rating during normal operation, and regulate the PV power output during abnormal conditions.

There are a number of factors to consider in determining the cost of a substation upgrades. The scope of the upgrade could include building a completely new substation on new land, installing a new substation transformer and circuit(s) in an existing substation, installing a new circuit at an existing substation transformer, or converting a 4kV substation to 12kV.[8] Broad assumptions were made for this analysis; in practice detailed engineering will determine the scope of the upgrade.

The base assumption for a substation upgrade is $10,000,000 which includes: two (46kV) terminations, two (2) substation transformers, two (2) 12kV switchgears, four (4) 12kV feeders, one (1) acre of land, and communication infrastructure. We unitized the cost on a per feeder basis with considerations of various factors. For example, if a substation transformer exceeded the 50% limit, the two circuits it serves require a substation upgrade. If the existing substation has space for an additional substation transformer, land costs were subtracted from the base $10,000,000 and divided by four feeders to arrive at the per feeder cost. In this example, the per feeder cost is $2,000,000. The range

[8] If 4kV substation transformers or circuits require an upgrade, we will convert that area to a higher primary voltage, instead of installing additional 4 kV substations. This is part of an overall strategy to convert 4kV areas to higher primary voltages. These costs were not included in the DGIP based upon the assumption that 4kV circuits would eventually be converted. However in this analysis these costs are included because the 4 kV conversion projects would not coincide with PV growth. This adds significant cost over what was reported in the DGIP. 4kV conversions are higher in cost than new substation installations ($5M vs $2-3M on a per feeder basis) because of the labor hours required to retrofit a circuit with higher primary voltage wires and transformers.

of costs used for a substation upgrade varies between $1,000,000 and $5,000,000 per feeder in 2016$. Each circuit was analyzed at a high level (without detailed engineering) to determine the most appropriate cost of the upgrade.

Battery energy storage systems. Deploying distributed battery energy storage systems behind or in front of the meter can relieve distribution system congestion and maintain operational flexibility. Strategically located storage can avoid conductor overloads, while simultaneously maintaining operational flexibility. Battery cost assumptions are provided in the resource cost forecast in Figure N-3.

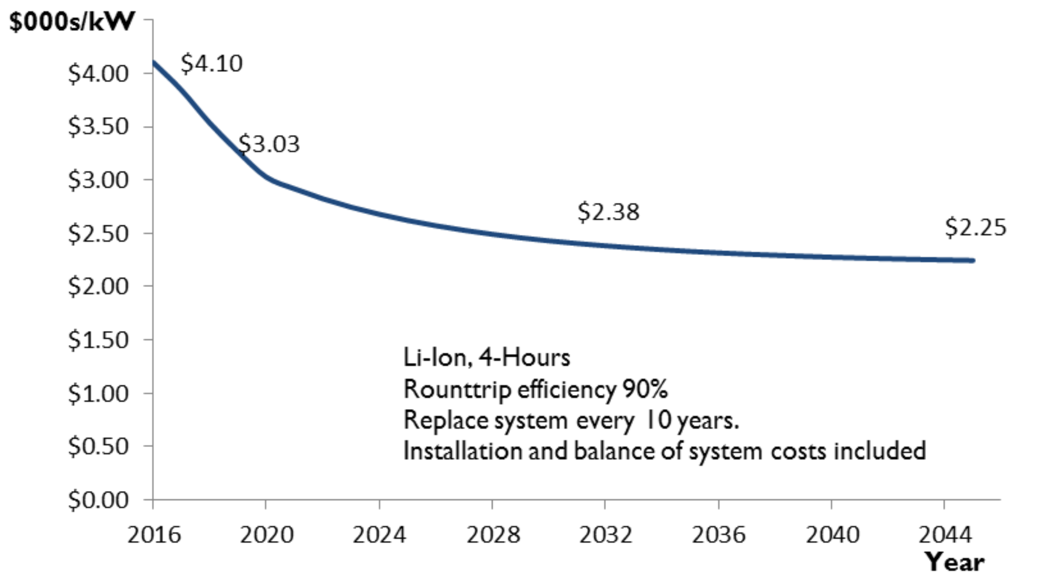

Figure N-3. BESS Cost Assumptions

Battery energy storage systems should be held accountable when deployed to relieve capacity and operational flexibility issues. One important design characteristic for this type of battery energy storage system is to ensure each morning the battery capacity is available to store that day's excess energy. For this analysis, a 4-hour charge/discharge cycle battery was assumed.

While battery energy storage systems may avoid the installation of a new substation, circuit or conductor upgrade, the current state of the technology estimate a 10-year lifecycle. Replacement storage quantities and costs were included in the integration cost estimates 10 years from the original deployment of a battery energy storage system. It should be noted that conductor upgrades and substation upgrades have life cycles in excess of 20 years; therefore, not assumed to require replacement. In addition, battery energy storage system failure must be accounted for. Rather than building redundant storage, the cost effective option is a combination of energy storage and circuit-level control of advanced inverter powered DG-PV. If a battery fails and compromises the safety and reliability of the system, DER control mechanisms should activate to regulate the active power output, particular if failures occur en masse.

Var compensation devices. Var compensation devices leverage modern power electronics to provide fast acting reactive power to reduce voltage fluctuations, and regulate circuit voltages to avoid the high voltage effects of deep penetrations of DG-PV. These devices come in many different forms: low voltage static compensators, fast switching capacitors, inline power regulators, and advanced inverters. These types of devices, located on the secondary part of the distribution system, can potentially provide more cost-effective and efficient regulation to mitigate voltage quality impacts and displace traditional, slower acting equipment such as capacitor banks and voltage regulators. This distributed voltage regulation technique represents a departure from traditional industry methods of voltage regulation. While we have started to demonstrate and assess these innovative devices, the technology is a relatively recent development and has yet to achieve widespread adoption across the industry. We will determine the viability and deployment of these devices once we complete our assessment of these devices from a planning and operating perspective.

To quantify the cost of these devices, representative circuits were modeled to determine the quantity of existing inverters that are required to have reactive power capabilities to mitigate existing high voltages. It was determined that for O‘ahu and Maui 12% of the existing inverter fleet would require retrofit. However, a smart inverter retrofit is not the sole method to resolve high voltage issues given the implementation challenges with customer ownership of the PV inverters. Therefore, the analysis assumed a non-specific solution that includes all device strategies discussed above. An estimated cost to install power electronic devices that provide reactive power compensation was based on a unitized cost estimated at $855 per kilowatt in 2016$. This cost was derived from an NREL report discussing PV costs for residential, commercial and utility-scale systems[9] in Hawai‘i.

Advanced inverter DER controls infrastructure. As PV continues to grow on our distribution system, distribution system management will become increasingly multifaceted and require controllability of customer DER assets by the system operator to maintain safe, efficient, reliable operations. Advanced inverters will play a pivotal role to enable controllability, which we now require as part of our most recent revisions to interconnection Rule 14H. The cost to implement DER controls include foundational infrastructure such as: advanced distribution management system, a distributed energy

[9] See Chung, Davidson, et al (September 2015). U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential Commercial and Utility-Scale Systems. Golden, CO: National Renewable Energy Laboratory, TP-6A20-64746. At 7-9. This report states the cost to install a 5.2kW PV system in Hawai'i is $3,280/kW in 2015$. The $855/kW unitized cost was derived by subtracting the supply chain, balance of system, PV module and racking, customer acquisition, overheads, and profit costs from the $3,280 estimate.

resource management system (DERMS), advanced metering infrastructure (AMI); however, for the purposes of the integration cost estimates, only infrastructure required to directly implement controls on a DER asset are considered. Controllability costs are not incurred until 2018, at which time it is assumed that the DERMS and AMI projects are installed and capable of initiating basic controls of DER assets. The cost of the DERMS and AMI projects were not included in this study's integration costs. It is assumed that every new DER system will be outfitted with the necessary hardware/software to enable controllability; this cost is estimated at $1,500 per system. Assuming an average PV system size of 6KW, the number of total PV systems installed each year was determined. This $1,500 per DER system cost estimate is a high-level estimation of the cost of communication hardware (i.e. communication gateway) and any associated firmware costs.

It is important to note that this technology is still largely being developed within the utility and solar industry.[10] We assumed for this study availability of these capabilities in 2018.

[10] The California Smart Inverter Working Group recently filed DER communication recommendations with its Public Utilities Commission; a decision is still pending. Arizona Public Service and Tucson Electric Power are currently running rooftop solar programs testing smart inverter capabilities, including inverter communications, http://www.solarelectricpower.org/utility-solar-blog/2015/january/arizonas-utility-owned-solar-programs-new-price-models,-grid-integration-and-collaboration.aspx.

Step 4: Quantify Integration Plans and Costs for All Solutions

Upon completion of the circuit specific analysis, the portfolio of integration solutions were each quantified into various strategies. This section describes the different strategies (and associated costs) that were considered to integrate PV in the base and high DG-PV cases. The strategies fell into two general categories—traditional or wires solutions and technology or non-wire solutions—that were then used to create three DER integration strategies in the base case and four DER integration strategies in the high DG-PV case.

- Strategy 1: Traditional or wires solutions to integrate the base DG-PV case.
- Strategy 2: Technology or non-wires solutions to integrate the base DG-PV case.
- Strategy 3: No storage solution with advanced inverter controls to integrate the base DG-PV case.
- Strategy 4: Traditional or wires solutions to integrate the high DG-PV case.
- Strategy 5: Traditional or wires solutions with advanced inverter controls to integrate the high DG-PV case.
- Strategy 6: Technology or non-wires solutions to integrate the high DG-PV case.
- Strategy 7: Least storage solution with advanced inverter controls to integrate the high DG-PV case.

Strategy 1 and 4: Traditional or Wires Solutions

Traditional or wires solutions solve thermal equipment overloads, degraded voltage quality, or loss of operational flexibility by upgrading or installing conductors, transformers, or voltage regulators. In these two strategies, operational flexibility is maintained by creating a new substation and/or circuits whenever the reverse power flow from excess PV generation exceeds 50% of the transformer rating.

Traditional upgrades address the root cause deficiency in the distribution system; these types of upgrades are proven, tested solutions with an asset life of 20+ years compared to less traditional solutions such as energy storage. However, depending on the scope of the solution, traditional solutions may have significantly longer installation times.

Figure N-4 through Figure N-9 summarize by island, the cost to integrate PV under strategy 1: traditional solutions in the base DG-PV case, and strategy 4: traditional solutions in the high DG-PV case.

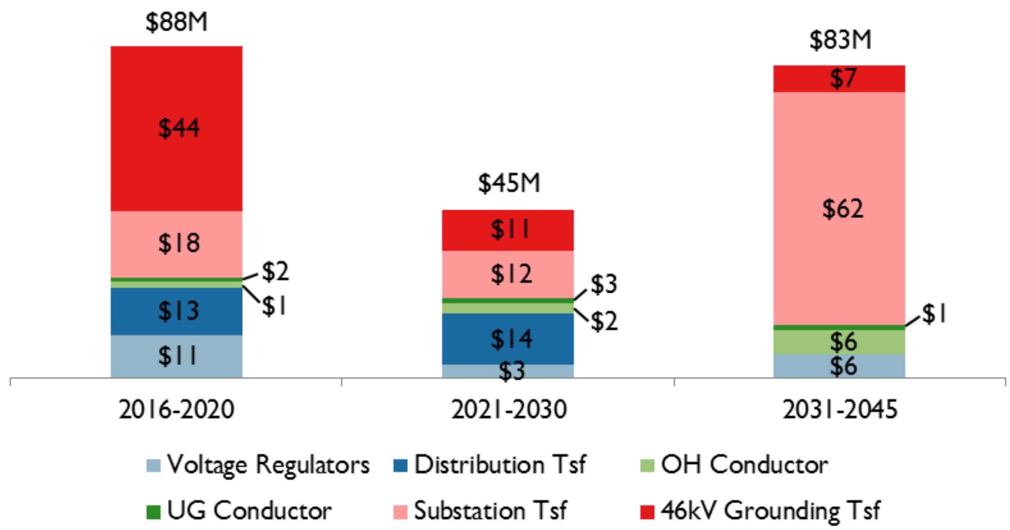

Figure N-4. O'ahu Island: Strategy 1 Annualized Integration Costs, Nominal $M

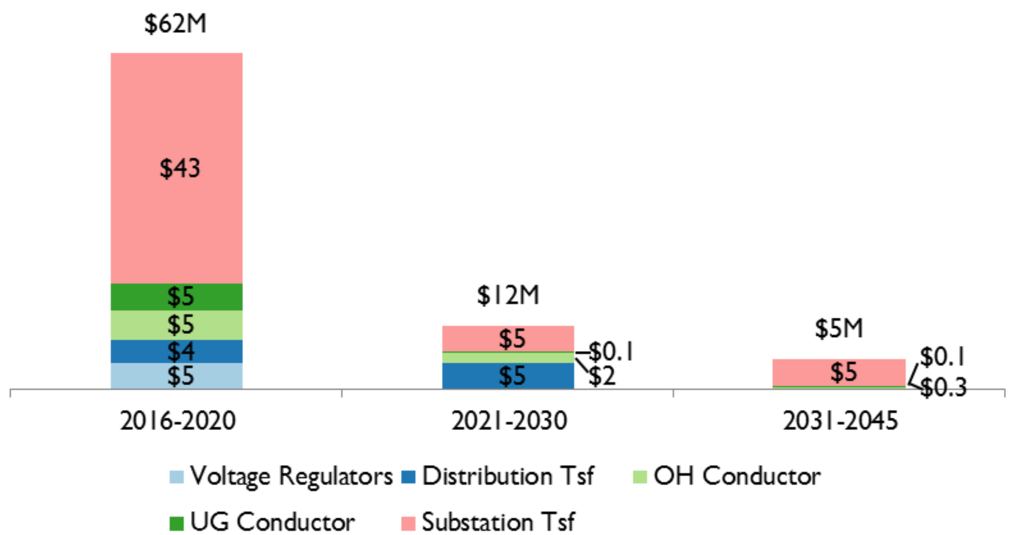

Figure N-5. Maui Island: Strategy 1 Annualized Integration Costs, Nominal $M

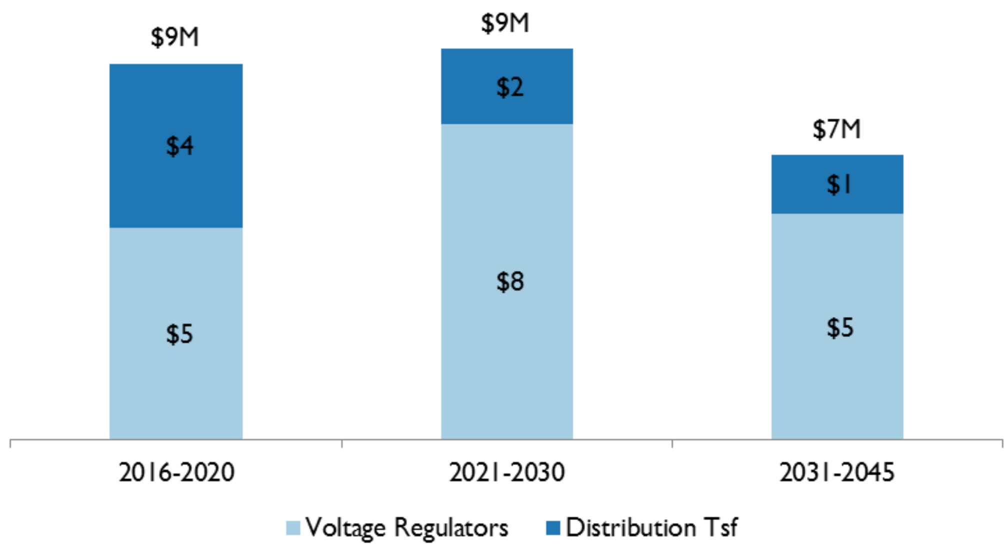

Figure N-6. Hawai'i Island: Strategy 1 Annualized Integration Costs, Nominal $M

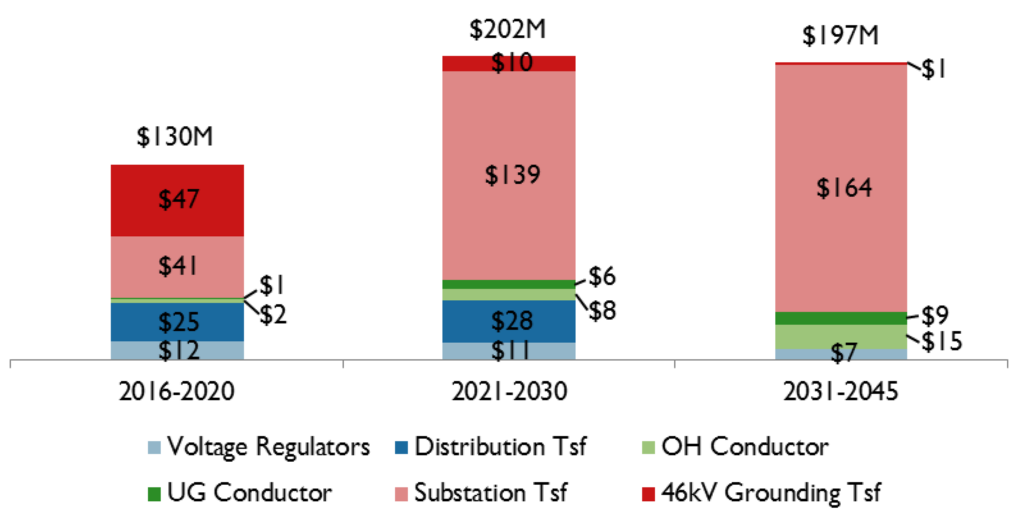

Figure N-7. O'ahu: Strategy 4 Annualized Integration Costs, Nominal $M

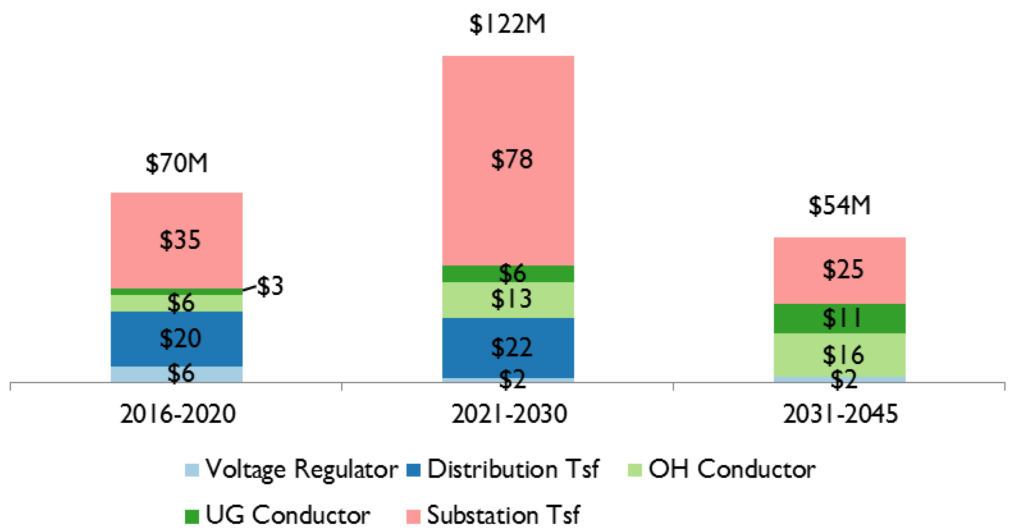

Figure N-8. Maui Island: Strategy 4 Annualized Integration Costs, Nominal $M

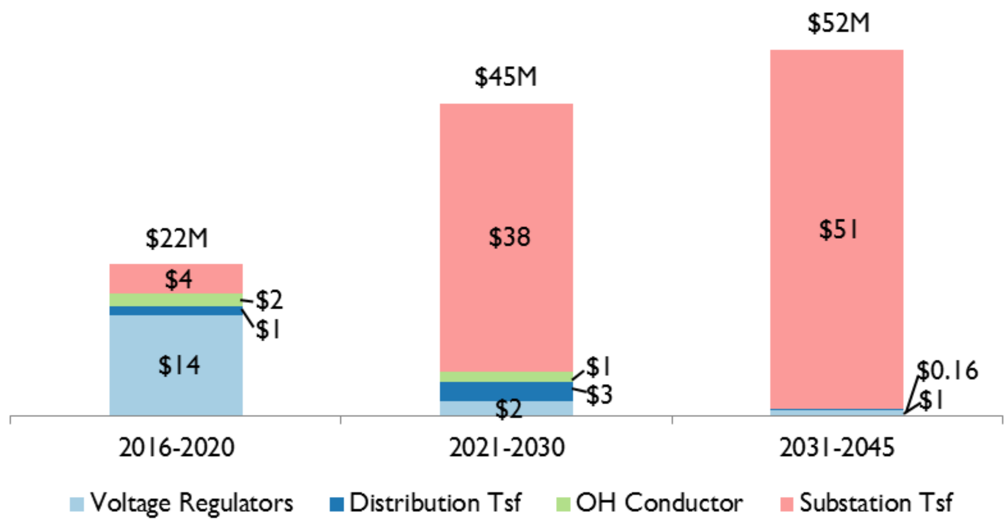

Figure N-9. Hawai'i Island: Strategy 4 Annualized Integration Costs, Nominal $M

Strategy 5: Traditional or Wires Solutions with DER Controls

This strategy is presented solely in the high DG-PV case because the PV penetration in the base case does not cause any substation transformer to exceed 50% of its thermal rating. In this strategy, the reverse power from PV is operationally allowed to exceed the 50% criterion but not exceed 100% of the substation transformer's thermal rating. In the high DG-PV case, any reverse power flow that exceeds of 100% of the transformer's thermal rating, triggers a substation upgrade; this criterion significantly reduces number of substation upgrades compared to Strategy 4. To protect the distribution system from the loss of all operational flexibility, controllability of advanced inverters for PV systems that exceed a circuit's operational circuit limit is a mandatory requirement. Much in the way that larger PV systems on the distribution system require direct control by the system operator,[11] the capability for the system operator to control these rooftop PV systems, aggregated by circuit, is essential to maintaining the operational flexibility and by extension, the safety and reliability of the distribution system.

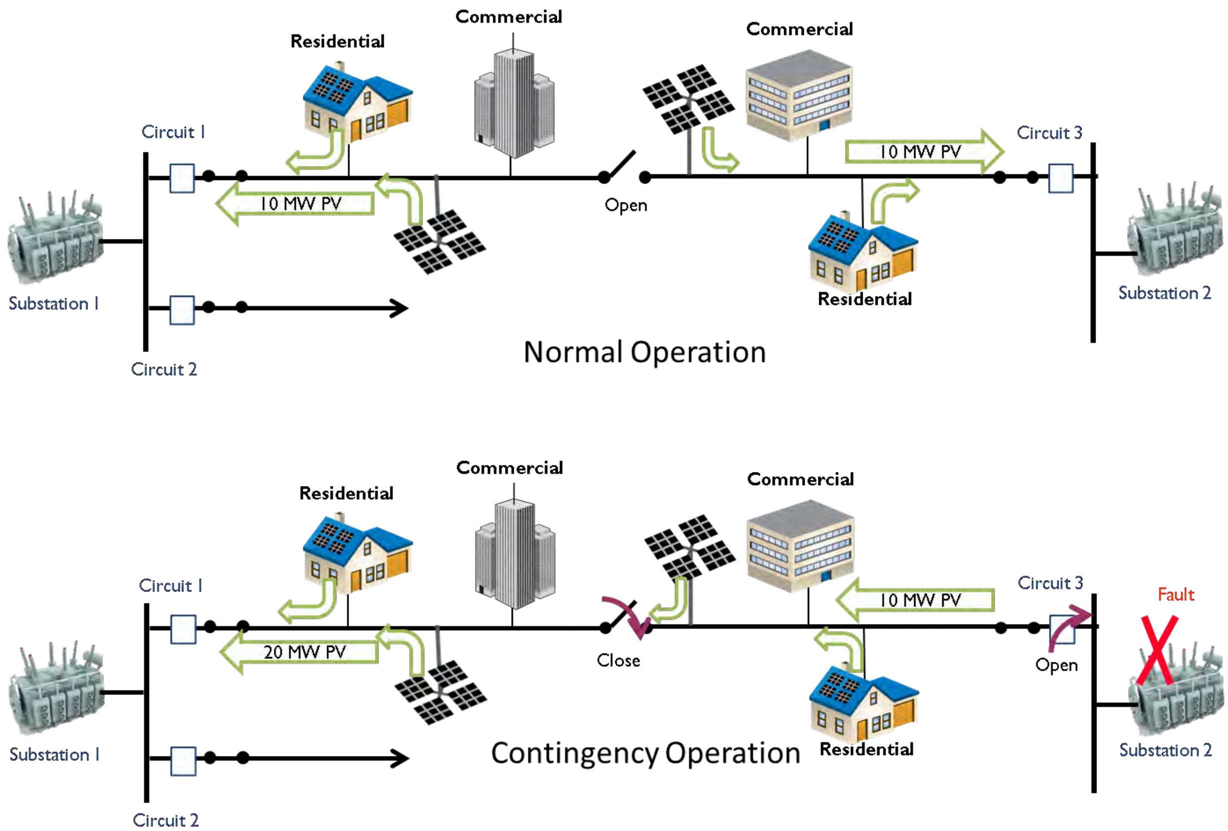

Figure N-10. Example of an Overloaded Substation During a Contingency Event

As Figure N-10 illustrates, if neighboring substations were both loaded with reverse power flow equal to 100% of their rated capacity (10MW), and one of these substations required servicing or suffered an outage due to a fault, the neighboring substation would need to provide reliable electric service to the circuit that is out of service. The out of service circuit would then be transferred to the neighboring substation transformer that remains in service to restore electric service to those customers experiencing an outage. Before doing so, the system operator would turn off the PV systems on the out of service circuit before restoring service to prevent those PV systems from turning on when service is restored. Failing to turn off the PV systems of the customers undergoing a transfer to

[11] Per Rule 14 paragraph H, supervisory control is mandatory for generating facilities with an aggregate capacity greater than 1MW to ensure prompt response to system abnormalities, and may be required for facilities between 250 KW and 1 MW. At Maui Electric and Hawai'i Electric Light, supervisory control is mandatory for facilities 250kW and greater. See HECO, MECO, HELCO Rule 14.

the neighboring circuit may then cause an overload of 200% (20MW) to the in-service substation transformer—the combination of the PV systems on the existing in-service circuits and the PV systems that were transferred from the now out-of-service circuits.

Figure N-11 through Figure N-13 summarize by island, the cost to integrate PV under strategy 5: traditional solutions with DER controllability in the high DG-PV case.

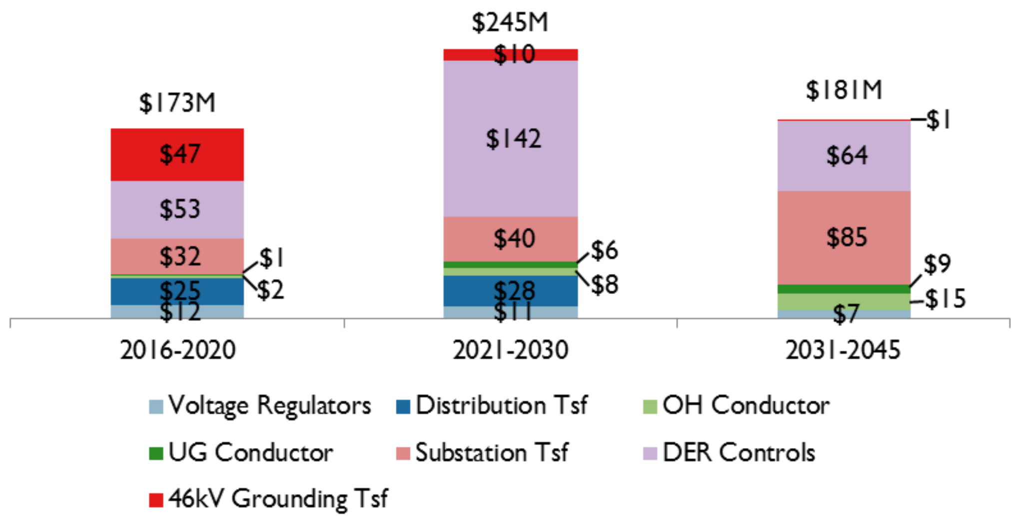

Figure N-11. O‘ahu: Strategy 5 Annualized Integration Costs, Nominal $M

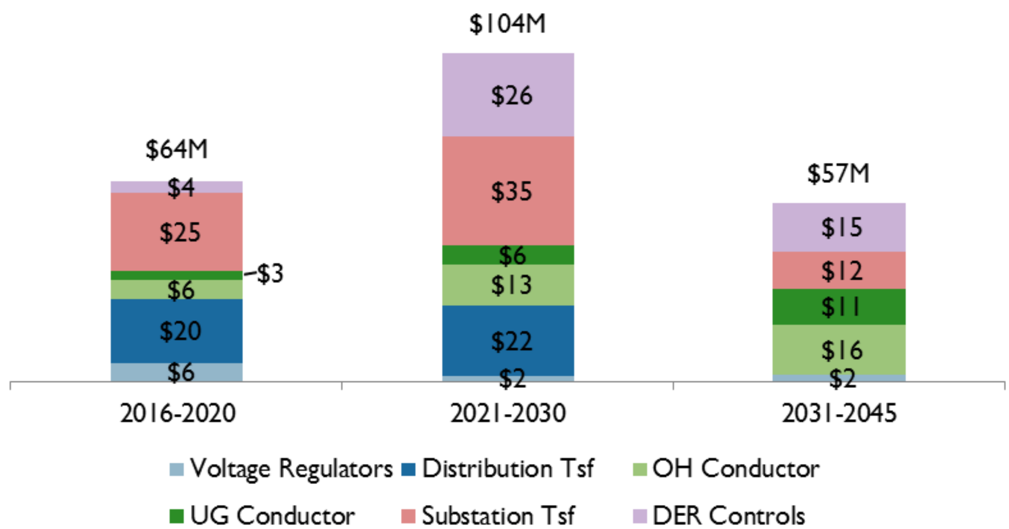

Figure N-12. Maui Island: Strategy 5 Annualized Integration Costs, Nominal $M

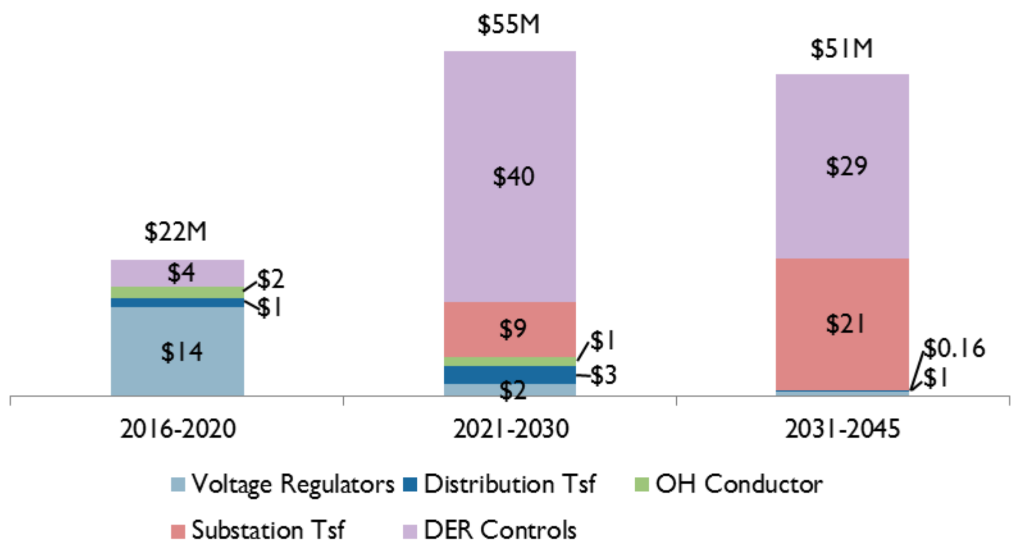

Figure N-13. Hawai'i Island: Strategy 5 Annualized Integration Costs, Nominal $M

Strategy 2 and 6: Technology or Non-Wires Solutions

Technology or non-wires solutions leverage new technologies and distributed energy resources to resolve PV impacts. Energy storage is selected to store excess energy thereby restoring any lost operational flexibility and avoiding the installation of new circuits or substations, as indicated in strategies 1 and 4. It is further assumed, that storage is strategically located on the distribution system to simultaneously alleviate overloaded conductors and service transformers.

One tenet of utility planning is to plan for failure of equipment. In the case of battery energy storage, if an energy storage system that was previously relied upon to alleviate an overload fails, contingencies must be taken to prevent the reverse power flow from the PV systems causing damage to the utility equipment. To plan for this contingency, PV facilities should be controllable through advanced inverters by the system operators in the event that a battery energy storage device fails, and consequently overloads equipment. If centralized control is unavailable, local energy management systems may autonomously manage the local energy while receiving signals from the utility during contingency operations to avoid unsafe operating conditions.

This strategy of utilizing battery energy storage systems is cost prohibitive compared to strategies 3 and 7; however, storage may provide other ancillary benefits—such as energy shifting and frequency regulation. Battery storage would also reduce sub-transmission congestion by reducing the amount of energy exported to the sub-transmission and transmission system.

Lastly, voltage quality impacts are mitigated with the use of var compensation devices as described in the previous section. While these technologies have yet to reach widespread adoption, this distributed voltage regulation philosophy and devices may represent the future of voltage regulation and improved distribution system efficiencies.

Figure N-14 through Figure N-19 summarize by island, the cost to integrate PV under strategy 2: technology solutions in the base DG-PV case, and strategy 4: technology solutions in the high DG-PV case.

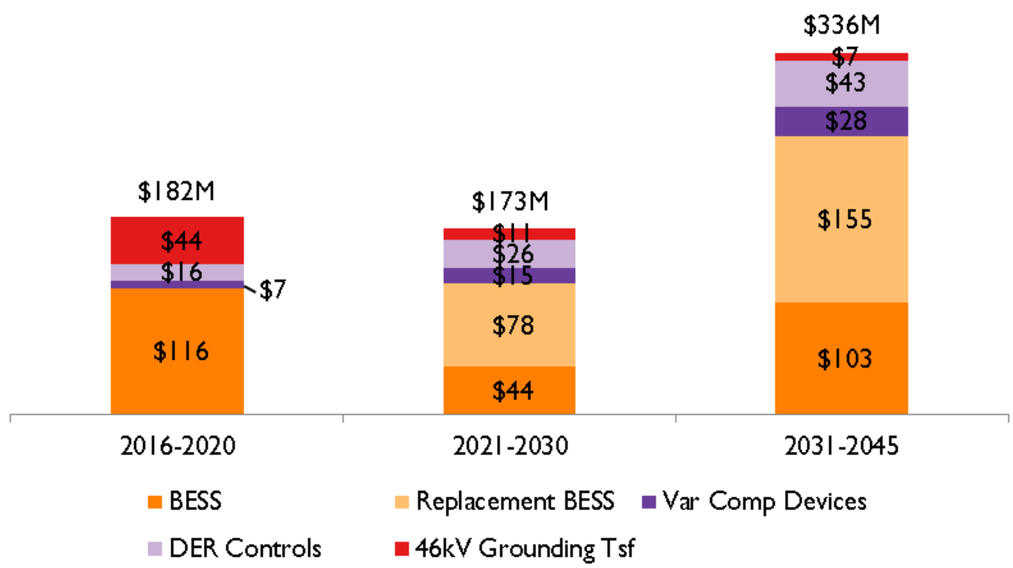

Figure N-14. O'ahu: Strategy 2 Annualized Integration Costs, Nominal $M

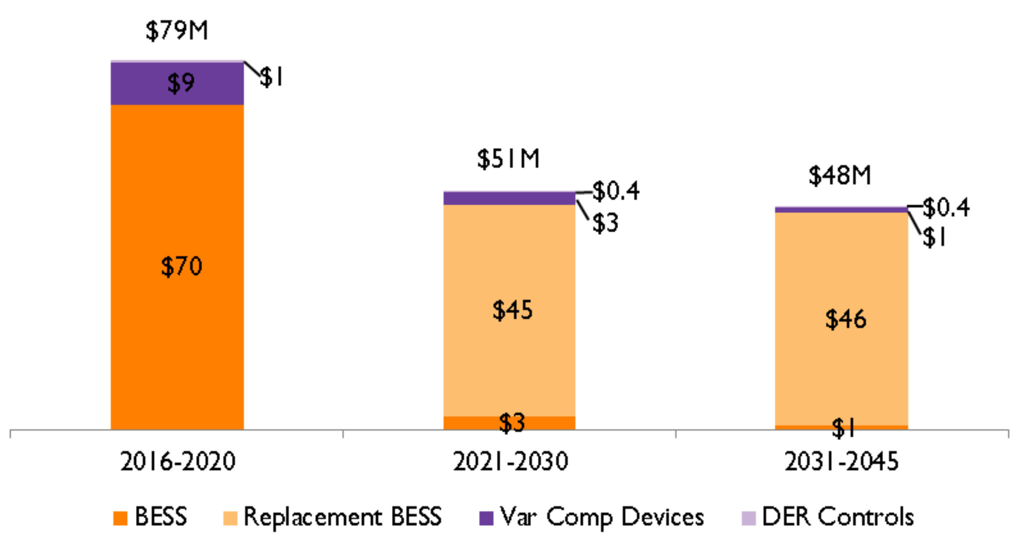

Figure N-15. Maui Island: Strategy 2 Annualized Integration Costs, Nominal $M

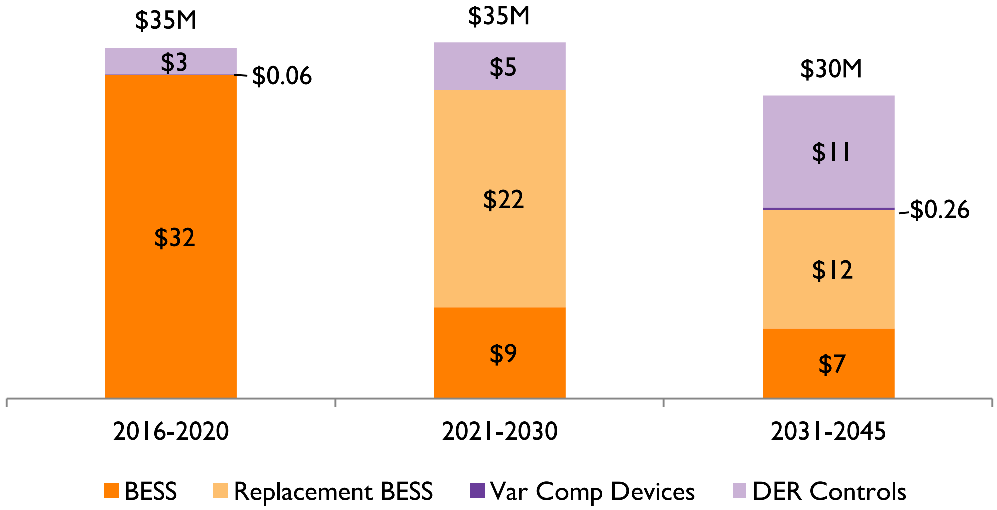

Figure N-16. Hawai'i Island: Strategy 2 Annualized Integration Costs, Nominal $M

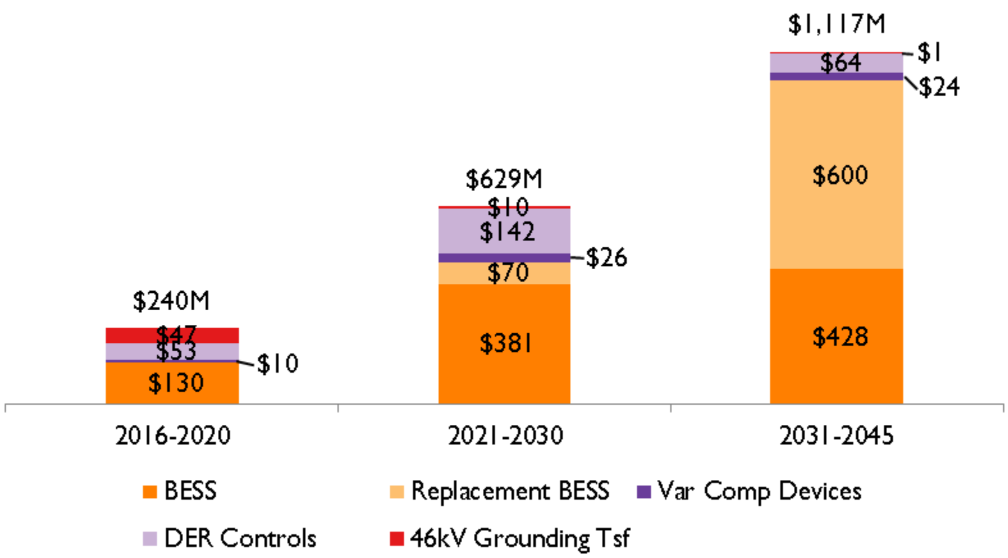

Figure N-17. O'ahu: Strategy 6 Annualized Integration Costs, Nominal $M

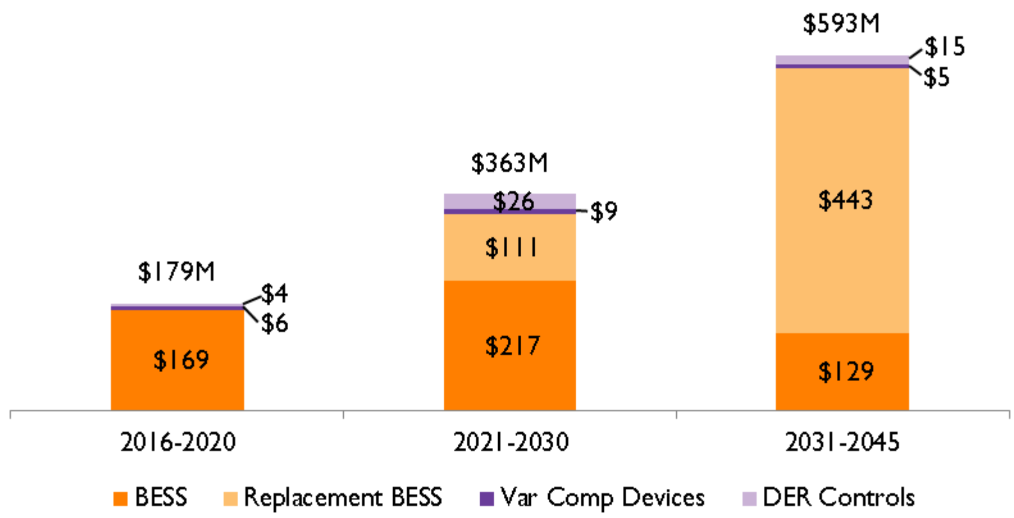

Figure N-18. Maui Island: Strategy 6 Annualized Integration Costs, Nominal $M

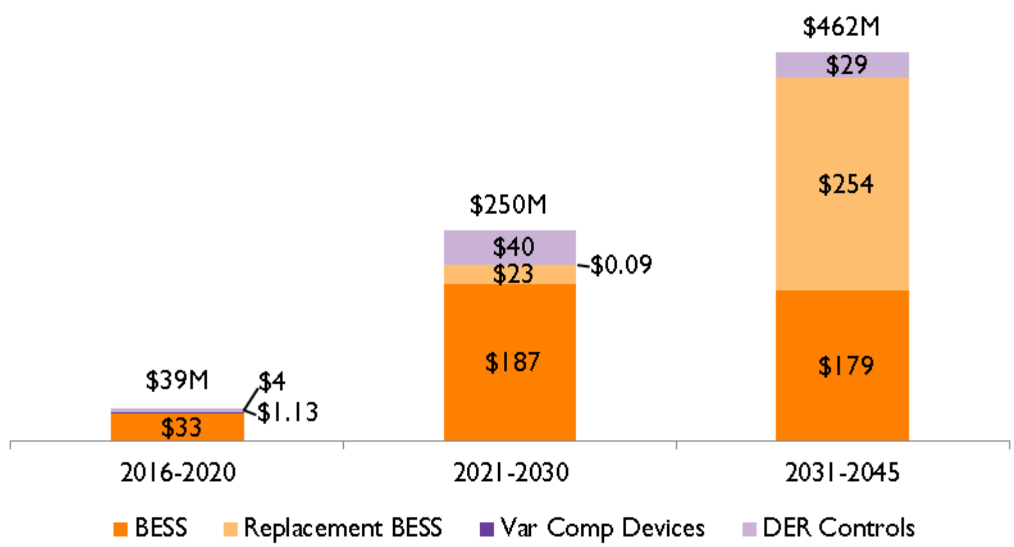

Figure N-19. Hawai'i Island: Strategy 6 Annualized Integration Costs, Nominal $M

Strategy 3 and 7: Least Storage Solution with Advanced Inverter Controls

This strategy is a variation of the technology solutions described in strategy 2 and 6, with the exception that normal operating practices are modified in that operational flexibility is not maintained during normal conditions, similar to strategy 5. The analysis demonstrates that storage is not required in the base DG-PV case and minimal storage in the high DG-PV case; however direct control of the PV facilities through the use of advanced inverter controls is required to allow the system operator to restore the operational flexibility when needed. Sub-transmission congestion is increased under this strategy but manageable with advanced inverter controls.

There is the potential for increased curtailment of distributed resources in these strategies but we are unable to quantify those amounts at this time, as it is highly dependent on the location of the DER assets.

Potential conductor upgrades are still required to avoid equipment overloads. Visibility of service transformer loading is more easily accessible than primary conductor loading. In this integration strategy, it is assumed that in the future, energy management system development will advance to have the capability to regulate the PV production in very localized areas as to not overload the service transformer. This measure of control can avoid service transformer replacements, and is reflected in the cost estimate of these strategies. Conductor upgrades were selected over storage because of the comparative cost effectiveness.

In the first 2 to 3 years of this strategy, voltage regulators and substation transformers are required at which time those solutions are phased out and replaced with advanced inverter controllability and var compensation devices.

Figure N-20 through Figure N-25 summarize by island, the cost to integrate PV under strategy 3 and strategy 7: least storage solution with advanced inverter controls.

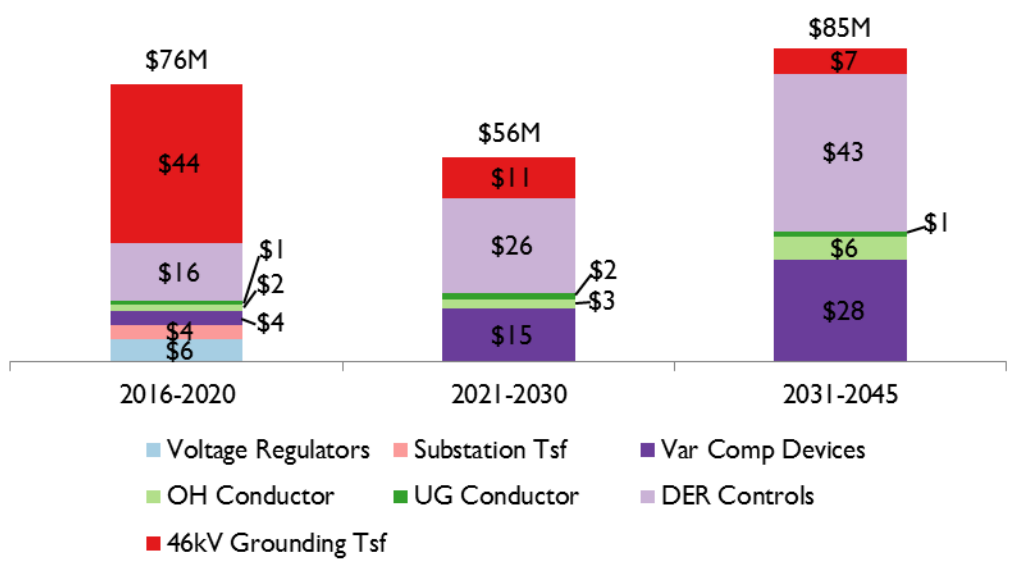

Figure N-20. O'ahu: Strategy 3 Annualized Integration Costs, Nominal $M

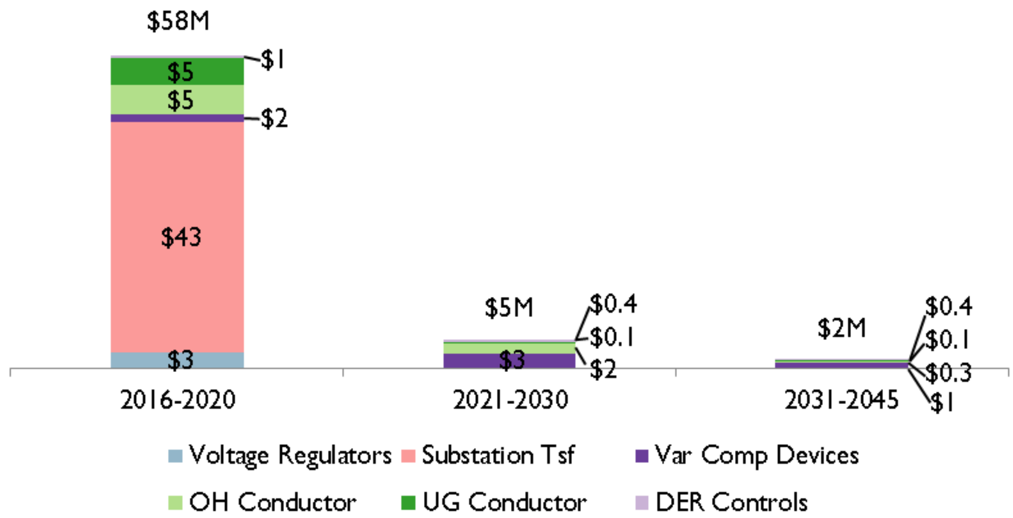

Figure N-21. Maui Island: Strategy 3 Annualized Integration Costs, Nominal $M

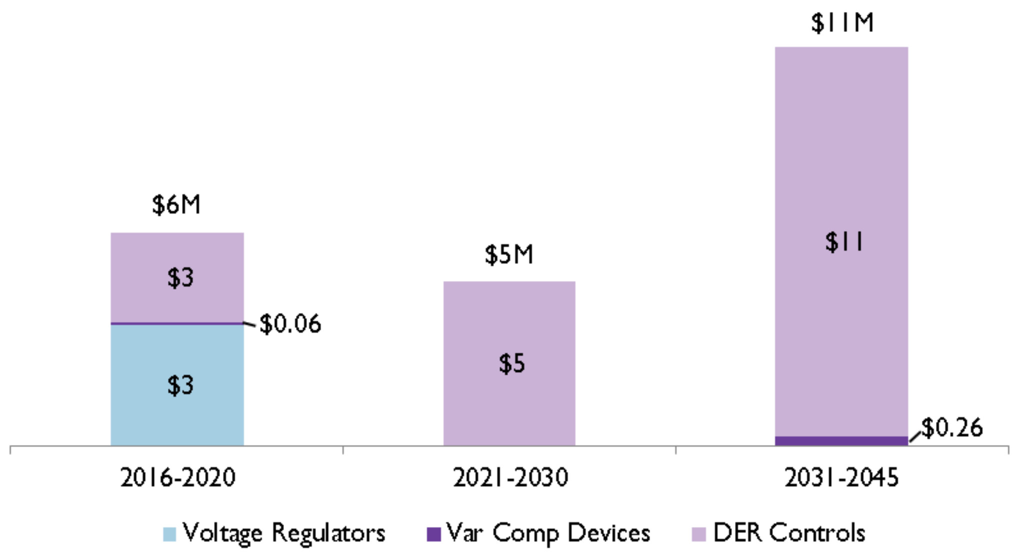

Figure N-22. Hawai'i Island: Strategy 3 Annualized Integration Costs, Nominal $M

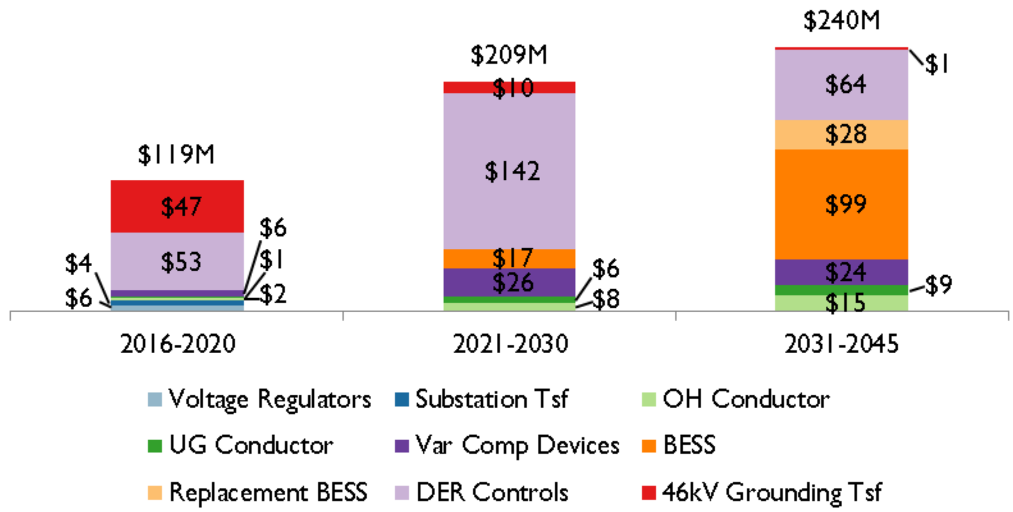

Figure N-23. O'ahu: Strategy 7 Annualized Integration Costs, Nominal $M

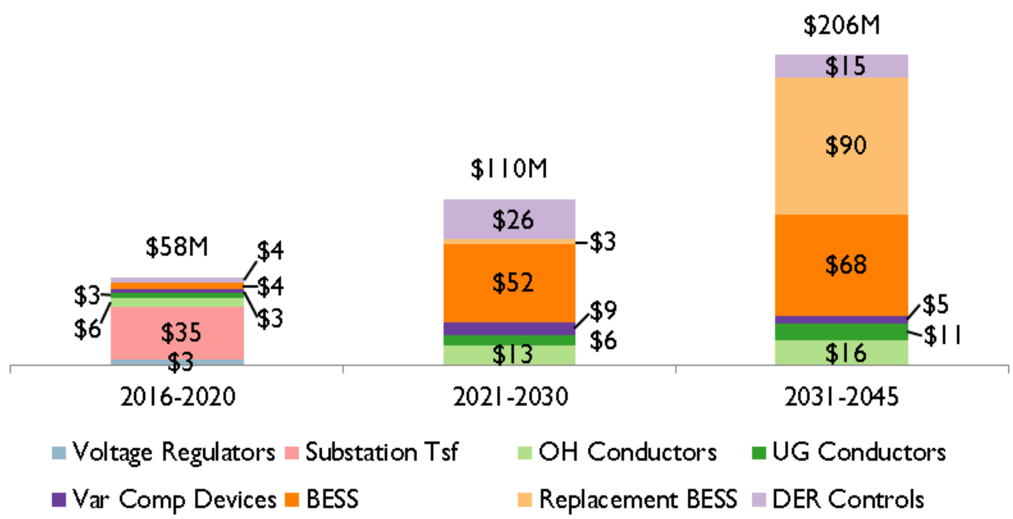

Figure N-24. Maui Island: Strategy 7 Annualized Integration Costs, Nominal $M

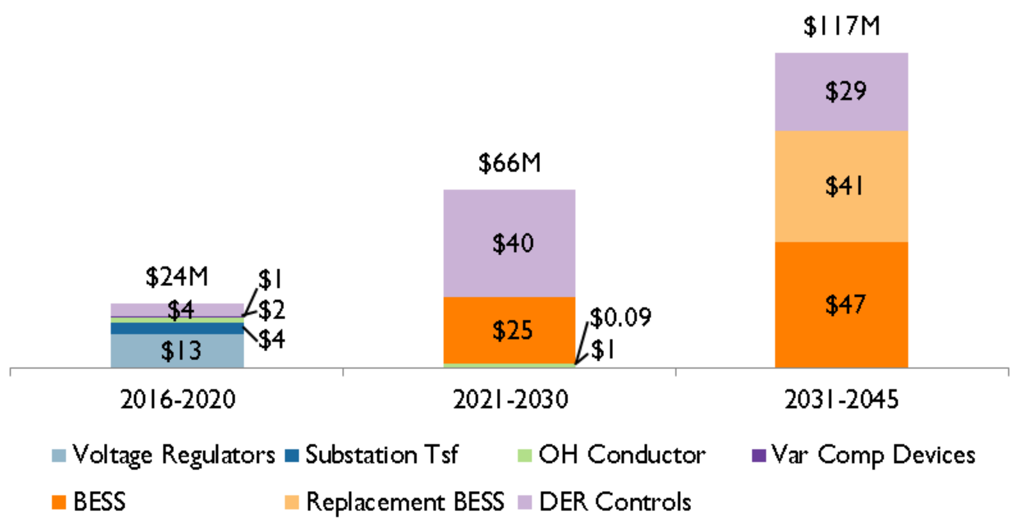

Figure N-25. Hawai'i Island: Strategy 7 Annualized Integration Costs, Nominal $M

Results of Integration Cost Analysis

Figure N-26 and Figure N-27 show the comparative costs for the different integration strategies for both the base and high DG-PV case per island in nominal $ with a 1.8% escalation rate.

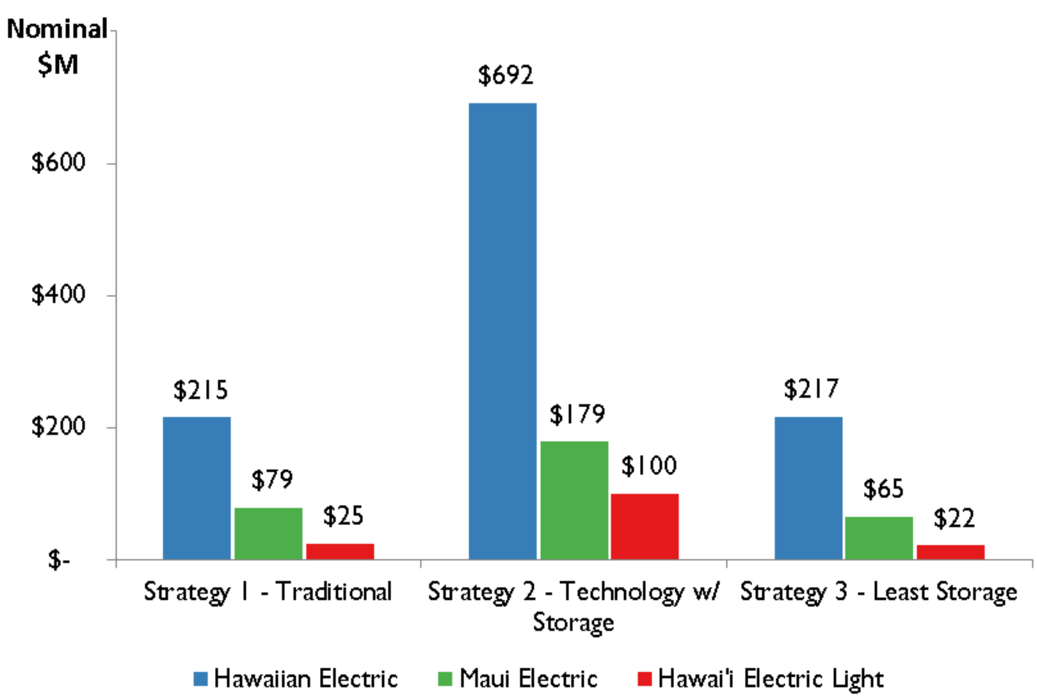

Figure N-26. Base DG-PV Forecast Total Integration Cost by Integration Strategy by Island.

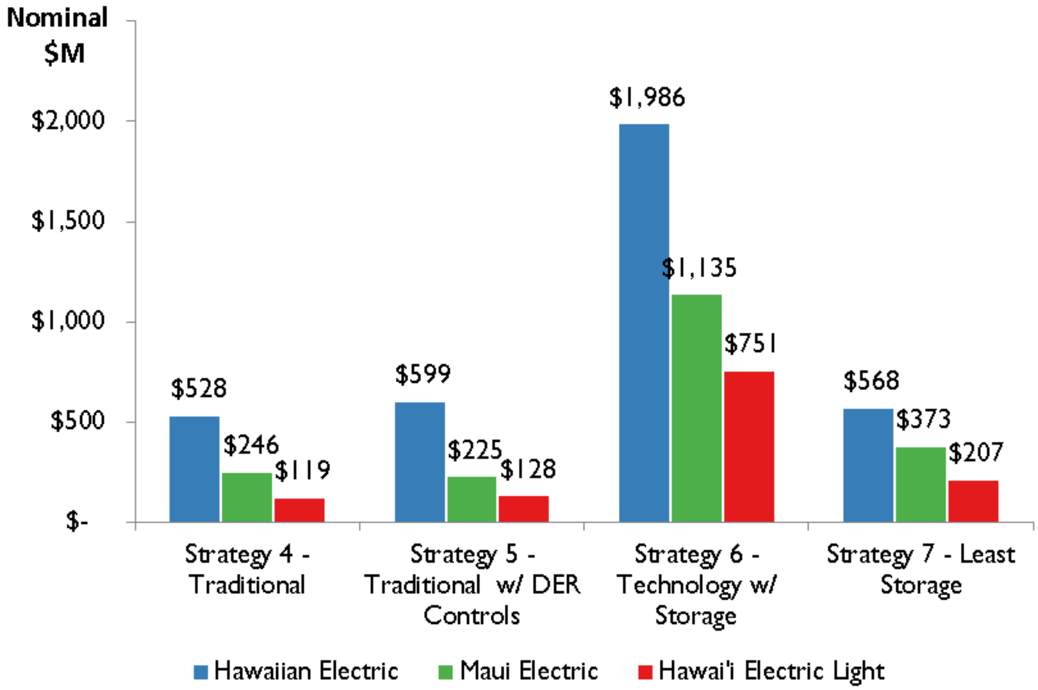

Figure N-27. High DG-PV Forecast Integration Cost by Integration Strategy by Island

When viewing the 30-year planning horizon, the least storage option is the is a cost competitive strategy, relative to the other options, across the three islands in the base DG-PV case (on Oʻahu the "traditional" strategy has a negligible cost difference when compared to the "least storage" strategy). However, in the high DG-PV case, the traditional integration strategy is the lowest cost strategy across the three islands. The least storage strategy becomes more cost competitive if the cost to implement advanced inverter DER controls is significantly lower than that assumed in this analysis.

Table N-4 summarizes the capital expenditures required in the near-term, 5-year period for each strategy, indicating that the least storage strategy is a cost competitive strategy.

Island Grid	Strategy 1	Strategy 2	Strategy 3	Forecasted PV
Oʻahu	$88M	$182M	$76M	608MW
Maui	$62M	$79M	$58M	125MW
Hawaiʻi Island	$9M	$35M	$6M	112MW

Table N-4. Near-Term Cost Comparison

It is likely that a mix of solutions from different strategies is deployed to resolve various integration issues in the near-term to strike the appropriate balance between cost and schedule. We prioritize solutions that meet near-term interconnection needs but are also useful in the longer term timeframe. These analyses represent a sound guide to the capital investments required to integrate various levels of DG-PV when considering a portfolio of solutions.

Full tabular results of the various strategies are provided in the later section titled, Integration Strategy Cost Estimates, including integration results for Lana‘i and Moloka‘i.

Step 5: Derive Integration Cost Estimates

The following cost curves (Figure N-28 through Figure N-33) were developed in real or constant 2016$ terms to define the relationship between total DG-PV megawatts interconnected and the associated integration costs. These cost curves can be used to estimate the integration costs for a range of DG-PV with proper escalation rates applied.

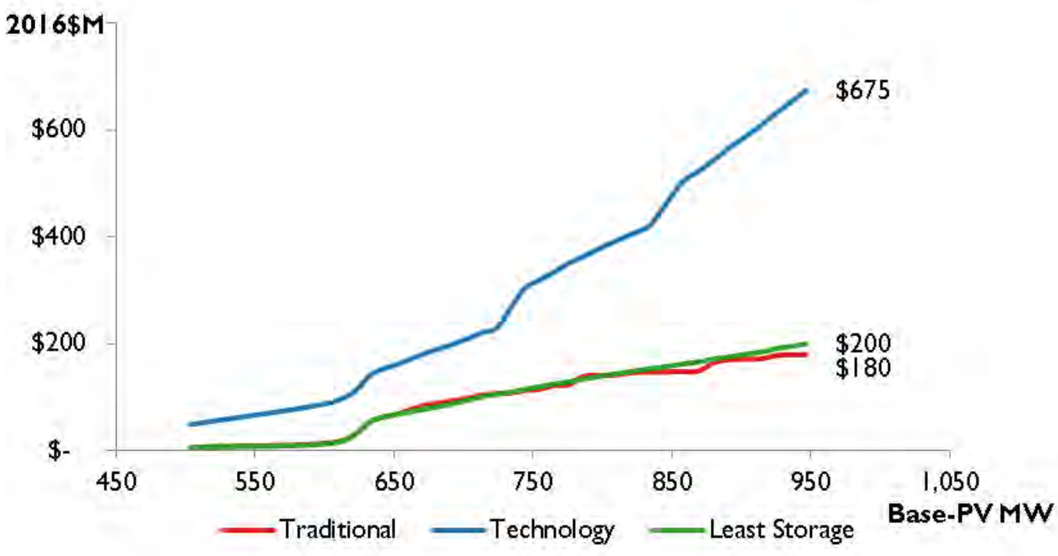

Figure N-28. O'ahu Base DG-PV Integration Cost Curve by Integration Strategy, Real $M

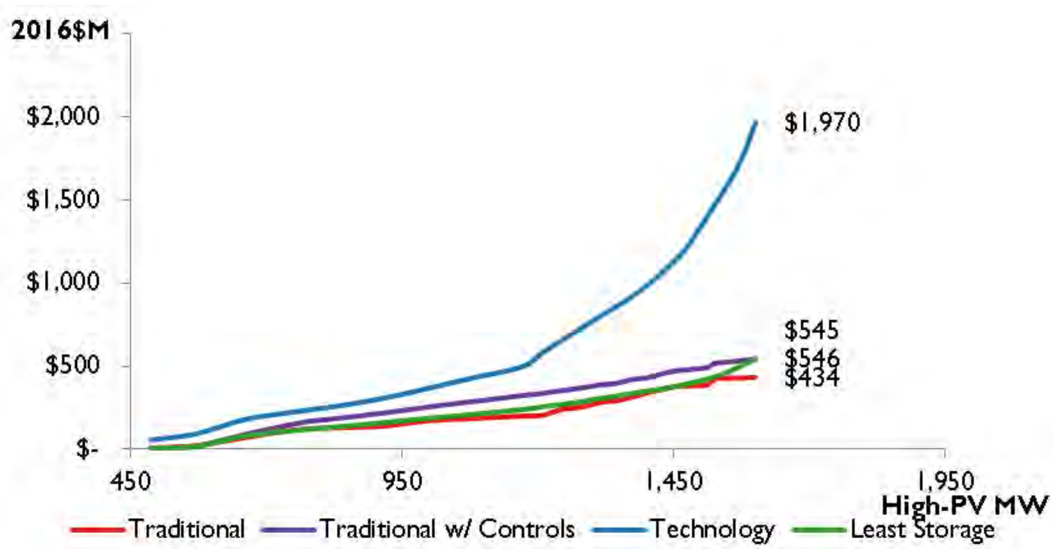

Figure N-29. O'ahu High DG-PV Integration Cost Curve by Integration Strategy, Real $M

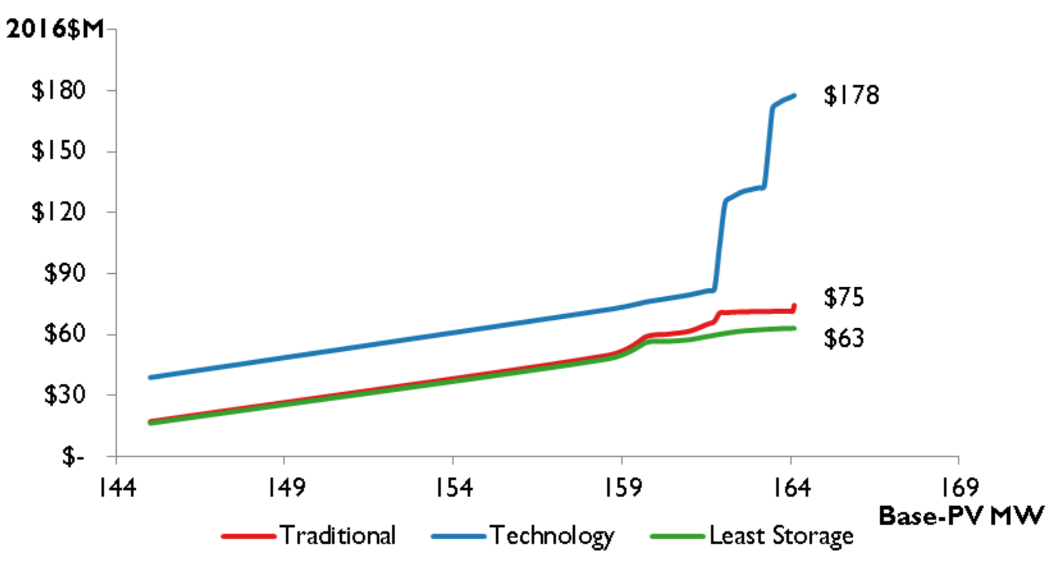

Figure N-30. Maui Base DG-PV Integration Cost Curve by Integration Strategy, Real $M

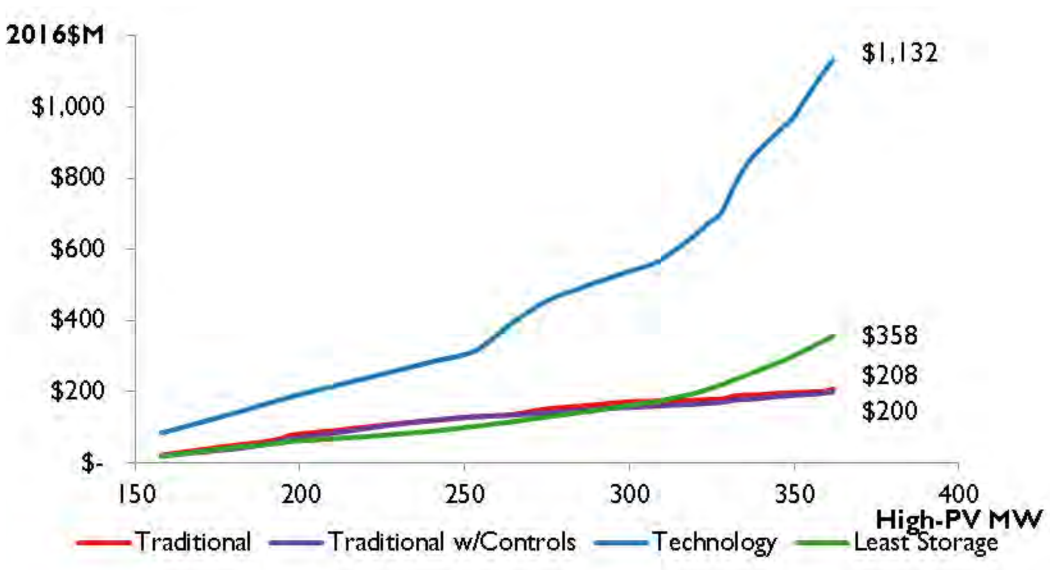

Figure N-31. Maui Island High DG-PV Integration Cost Curve by Integration Strategy, Real $M

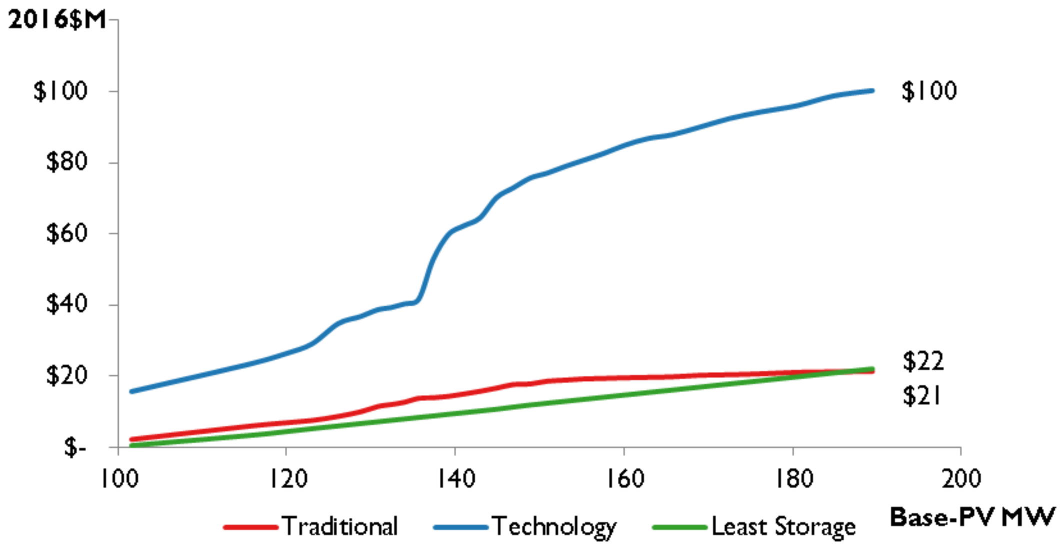

Figure N-32. Hawai'i Island Base DG-PV Integration Cost Curve by Integration Strategy, Real $M

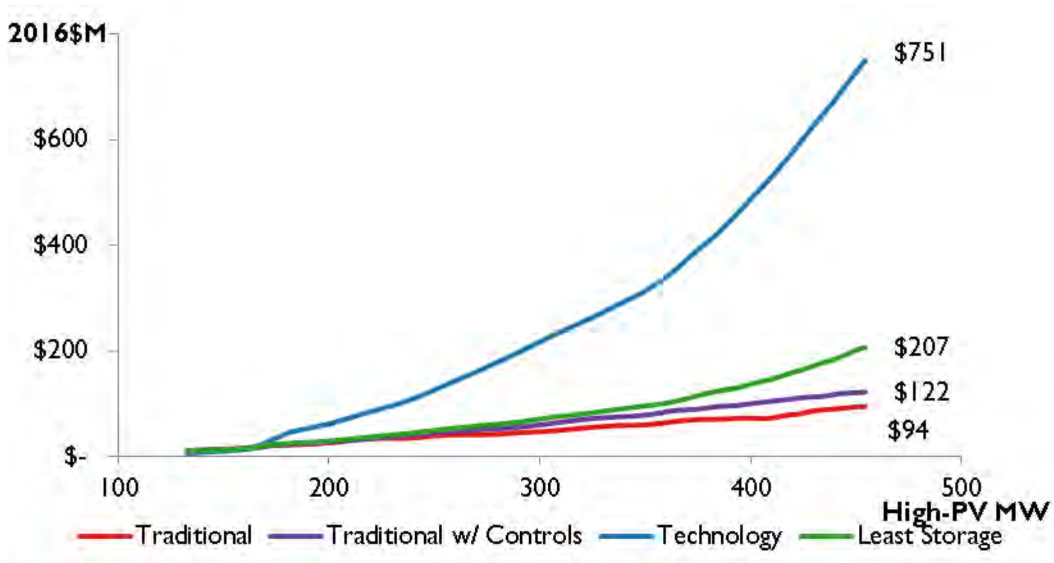

Figure N-33. Hawai'i Island High DG-PV Integration Cost Curve by Integration Strategy, Real $M

Integration Plans and Costs Sensitivities

Integration costs are sensitive to different policy decisions. For example, the vast majority of substation upgrades can be avoided if interconnection of PV is limited to the operational circuit limit until advanced inverter DER controllability is implemented.

Near-Term Capital Investments

Many of the near-term investments correct the deficiencies in power quality caused by the net energy metering program. If a program to retrofit net energy metering PV systems with advanced inverters, energy storage, or export limits were instituted, new grid export systems can sustainably interconnect at a lower capital integration cost. Alternatively, limiting DG-PV installation to no greater than the circuit's hosting capacity would reduce integration costs.

Energy Storage and Demand Response

Though storage was shown to be cost prohibitive, the figures below illustrate the storage requirements to integrate DG-PV in the base and high DG-PV cases. One PV integration benefit to storage at the circuit level is its ability to resolve potential sub-transmission or system level impacts by storing excess PV energy, while providing grid benefits with the discharge of the stored energy. Because of the interest in energy storage, the quantities of storage determined in this analysis are shown in Figure N-34 and Figure N-35.

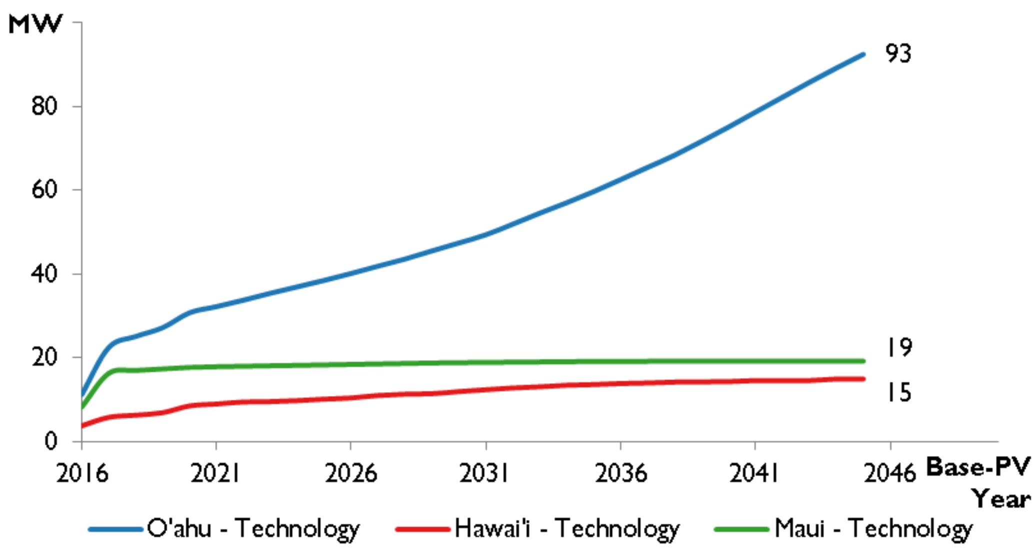

Figure N-34. Storage Requirements Determined in Strategy 2, by Island

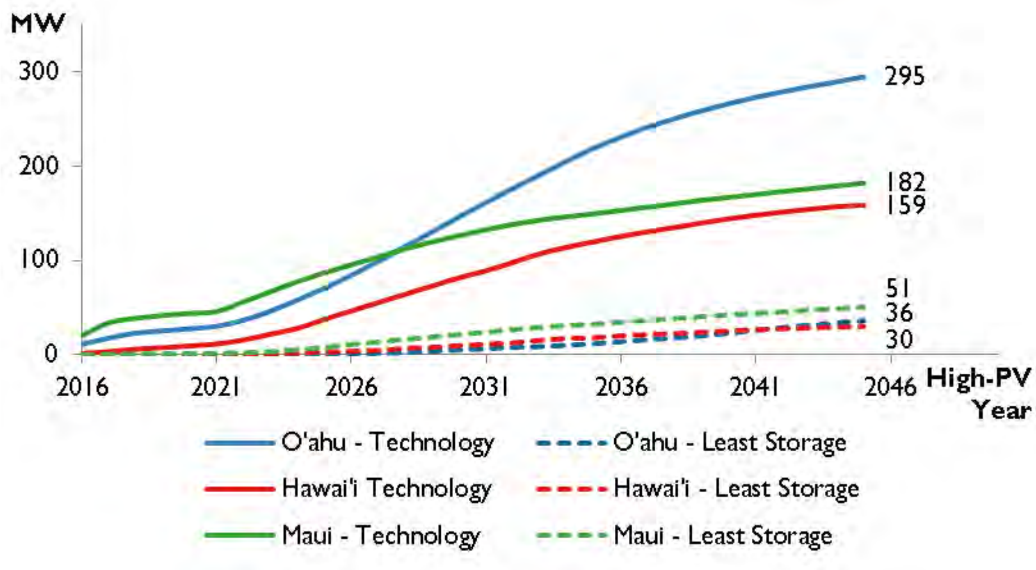

Figure N-35. Storage Requirements Determined in Strategy 6 and 7, by Island

If an energy storage system demand response program can closely coordinate deployment of assets to meet circuit needs, customer investment in storage can offset part of the capital costs associated with integration strategies 2 and 7.

Modified Load Profile

If customer behavior and demand response can effectively modify the traditional load profile of a distribution circuit to one that aligns customer consumption with DG-PV production (as illustrated in the Figure N-36), then the circuit hosting capacity would increase, and integration costs would be reduced in the mid- and long-term.

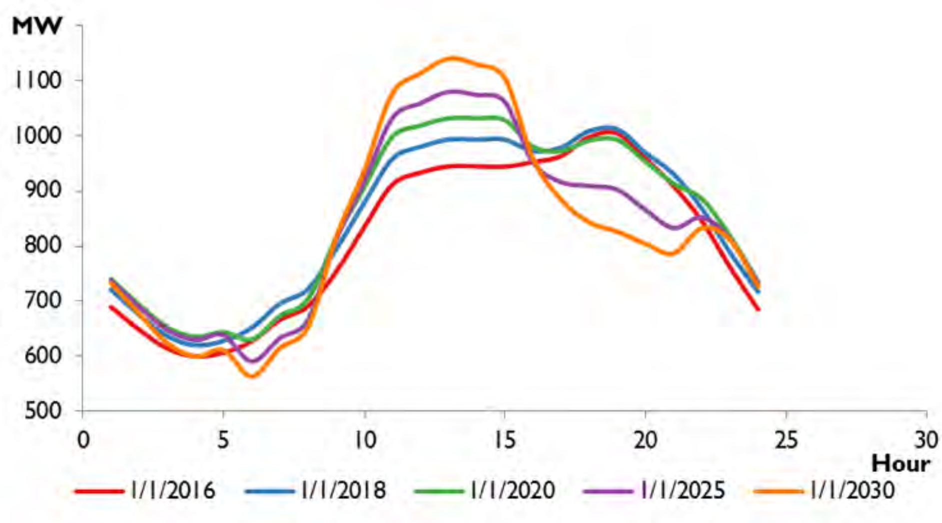

Figure N-36. Modified Load Profiles from Changing Customer Behavior and DR

Sub-Transmission Impacts

Within the seven integration strategies described above, sub-transmission impacts were not analyzed; at its current state, significant impacts to the sub-transmission system have not been observed. Where utility scale projects are interconnected to the sub-transmission system, interconnection studies were performed to resolve such impacts on a case-by-case basis. Based upon the recently completed circuit hosting capacity analysis in combination with the forecasted rooftop PV in this report, additional sub-transmission analysis will be required in the future, and would follow the process laid out in the circuit hosting capacity analysis. It would be reasonable to assume that impacts to the sub-transmission system would occur if all circuits connected to the sub-transmission circuit were built out with DG-PV to its circuit hosting capacity limit.

Based upon past interconnection studies, the recurrent technical issues on the sub-transmission system are: equipment overloads and ground fault overvoltage. The DGIP indicated the requirement for grounding transformers on the sub-transmission system to address ground fault overvoltage. Ground fault overvoltage can occur from a sub-transmission fault where the feed-in of fault current from the PV systems on the distribution system create a neutral-shift, ground fault overvoltage. Since the filing of the DGIP, we conducted an inverter ground fault overvoltage study with the National Renewable Energy Laboratory[12] to study the inverter behavior during single line to ground faults. While the tests were positive for distribution-level faults (wye-ground: wye-ground transformer configurations), testing of sub-transmission faults (delta-wye-ground transformer configurations) was inconclusive as to whether inverters will cause damaging ground fault overvoltages. More analysis and examination of this issue is necessary, so the integration costs conservatively assumed that sub-transmission grounding transformers were required where needed. On O‘ahu, 59 sub-transmission lines will exceed 100% penetration of daytime minimum load, requiring an installation of a grounding transformer on each of these circuits at a cost of $61M.[13] Each grounding transformer installation is $950,000 per transformer.

As congestion on the sub-transmission system increases interconnection costs for future sub-transmission generation increase, or in certain situations preclude future interconnections of sub-transmission projects (utility scale PV, wind, community based renewables, or firm thermal generation).

Technology integration strategies 2 and 6 depend heavily on energy storage deployment, effectively reducing the export of energy to the transmission system, and lowering the likelihood for sub-transmission capacity issues. Whereas, least storage strategies 3 and 7

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[12] Hoke, Nelson, et al (August 2015). *Inverter Ground Fault Overvoltage Testing*. Golden, CO: National Renewable Energy Laboratory, TP-5D00-64173.

[13] The Maui Electric and Hawai'i Electric Light systems do not have a sub-transmission system.

Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

allow all energy above the operational circuit limits to flow to the sub-transmission system; thereby, increasing the likelihood for sub-transmission capacity issues.

One solution to consider in resolving potential sub-transmission congestion can be in the form of autonomous scheduled active power control or regulation or dynamic active power regulation remotely set by a system operator through the use of advanced inverters. This reserved active power can then be used for upward regulation, akin to the current operation of the bulk generating system. This solution would require SCADA for all elements of and equipment on the circuit. If PV is operated in this mode of operation, the sub-transmission congestion issues are effectively reduced by the reduction of reverse power flow.

Additional Considerations

Ancillary Services

Allowing reverse power flow up to 100% of the substation transformer—as in Strategies 3, 5, and 7—may preclude distributed resources from providing certain ancillary services because equipment will be near or at capacity. If for example, fast frequency response is desired but the transformer is loaded to full capacity, there is no additional capacity to provide services. However, using storage or scheduled active power control as part of a demand response program can create the necessary capacity to provide those services. These distributed energy resources and its intended operation must be holistically integrated in the overall planning of the distribution system.

Underfrequency Load Shed Scheme

With our distribution systems forecasted to experience deeper penetrations of PV, the underfrequency load shed scheme will continue to function at reduced effectiveness. As substations become net generators instead of net consumers of load, the shedding of the sub-transmission lines or distribution substations during underfrequency contingencies may further deepen the frequency sag. We are in the process of modifying our current underfrequency load shed scheme to better function under our high DG-PV environment. However, the forecasted PV growth further reinforces the need to design the system to avoid any load shedding during loss of generation contingencies.

Distribution System Overview and the Planning Process

The distribution system is the part of the electric power system that distributes or disperses power from the transmission system to individual customers. To deliver electricity to spatially diverse customers, engineers must strike the appropriate balance between reliability and power quality in order to design an economically viable distribution system.

The term "one-way power flow" is often said to describe the traditional method of power system design. One example of one-way power flow refers to the architecture of the distribution system. Due to the historical nature of the electric system, our distribution systems are predominantly designed as a radial system; that is, starting at the substation the distribution circuit is designed to handle greater capacity (or bigger wires) and tapers outward (or designed with less capacity, smaller wires) as the system distributes power to customers farther away from the substation. In other words, the capacity of the distribution circuit closest to the substation is the greatest as it must have the throughput to push power to all customers on a circuit. As one moves towards the end of a circuit (farther away from the substation), there are less customers left to serve; therefore, less capacity or throughput is required. When considering distributed generation, as more sources of generation are installed deeper into the distribution system, the smaller wires at the end of the circuit may lack the capacity to accommodate excess energy that flows back towards the substation.

One major component of the distribution system (Figure N-37) is the distribution substation; this is the point in the electric power system where the transmission or sub-transmission system delivers power at high voltages and converts the power to medium voltage for distribution of power at safer and more economical means. Our system consists of 2,400 volt, 4,160 volts, 11,500 volts, 12,470 volts, and 24,940 volt systems; these voltages are also known as the primary part or primary voltage of the distribution system. The substation generally feeds two circuits (or feeders) that serve as the means to deliver power to customers—circuit or circuits are often seen as poles and wires at the side of a road. Higher voltage distribution circuits have more capacity than lower voltage distribution systems. The lower voltage distribution systems—2,400 volt and 4,160 volt—are at higher risk for power quality and capacity issues. Often times, these issues are resolved by converting these circuits to a higher voltage, like 12,470 volts.

The final major component of the distribution system is the distribution transformer, sometimes referred to as the service transformer. This piece of equipment converts the medium voltage, 2,400 through 24,940 volts, to a lower voltage, 120/240 volts for final delivery to customers. The majority of appliances and devices used by consumers operate at 120 or 240 volts. Residential customers normally share a distribution transformer, and are delivered power via wires that branch out from transformer to each individual home. Larger customers who have bigger load requirements often have a dedicated transformer and service connection.

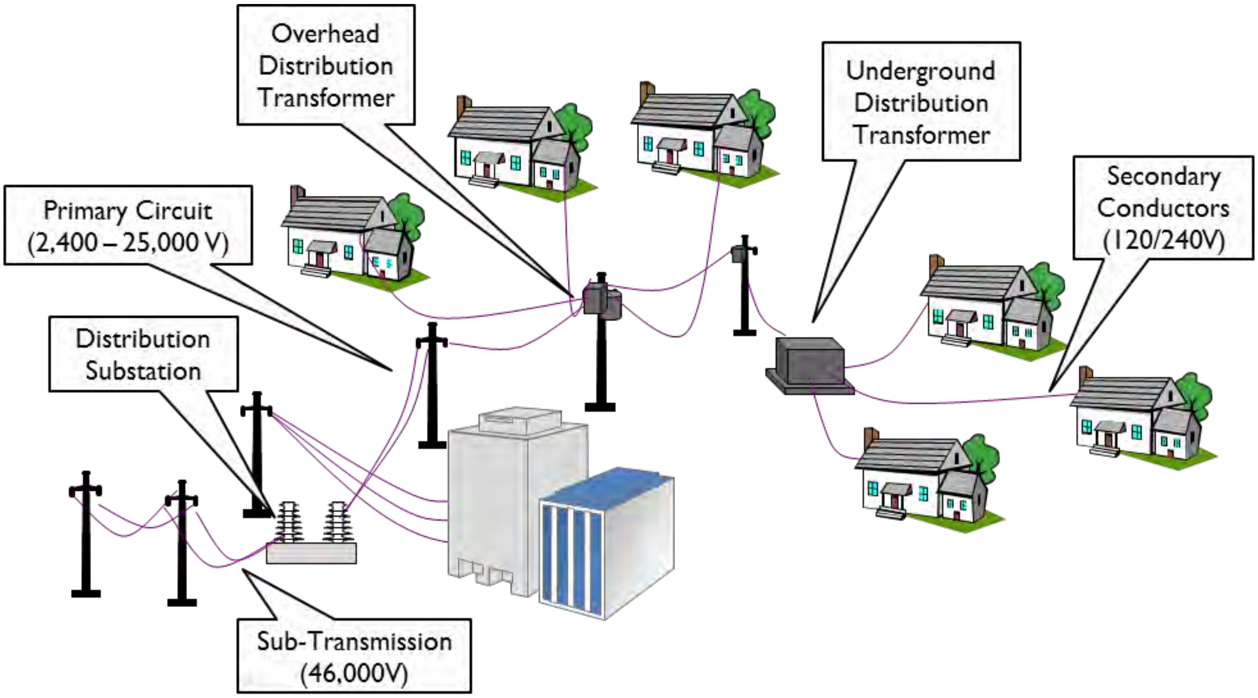

Figure N-37. Illustration of the Major Components of the Distribution System

To ensure the reliability of electric service to all customers, radially fed circuits are designed to be tied to one another, providing operators flexibility. The tying of circuits within the distribution system provides system operators the flexibility to re-configure the distribution system to restore power during a contingency and provide continuity of service—a power outage, equipment failure planned and unplanned maintenance. Distribution planners also re-configure circuits to maintain reliability and power quality for customers; for example, significant load growth may create power quality or capacity issues, in which case, a portion of a circuit is permanently transferred to another circuit to avoid overloading equipment or degrading power quality.

Figure N-38 illustrates the operational flexibility concept. Should a substation be taken out-of-service, planned or unplanned, a neighboring substation can restore power by closing a switch that ties the two circuits together, but normally open during normal operations.

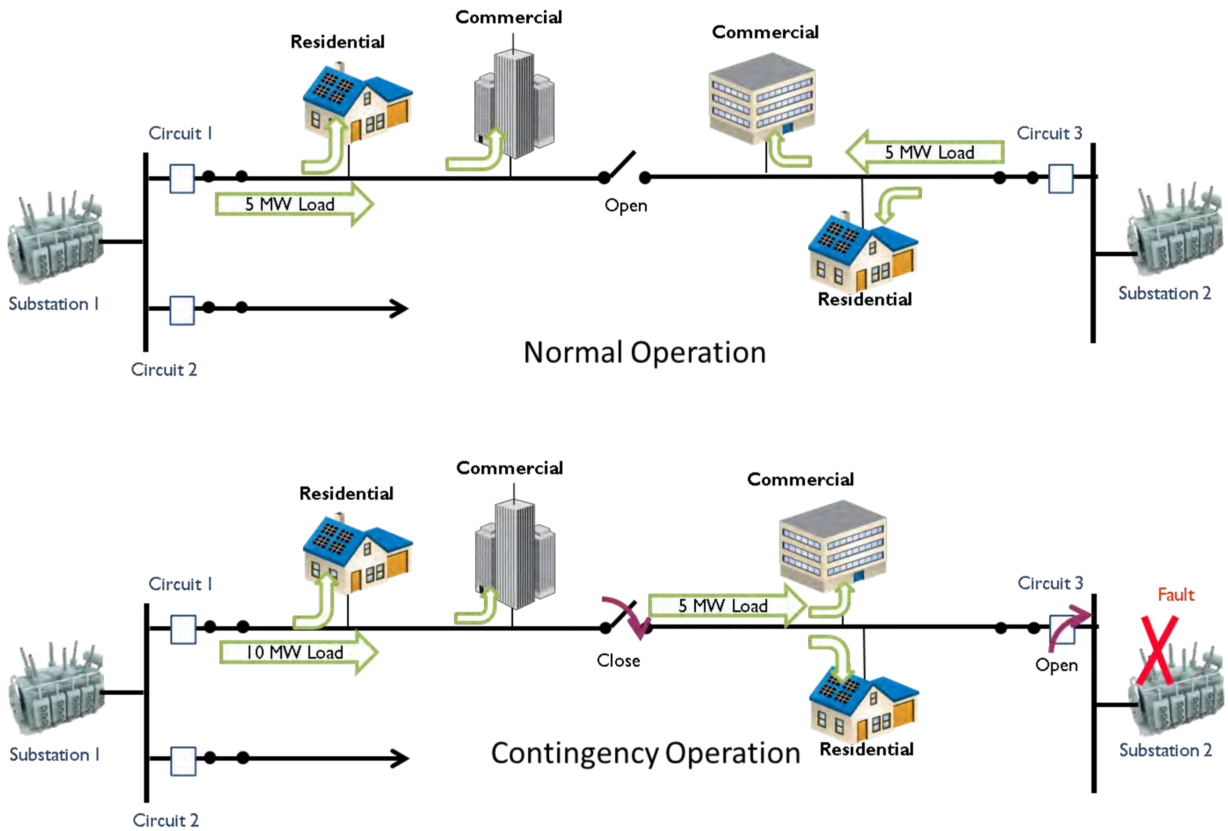

Figure N-38. Illustration of Operational Flexibility

Maintaining this operational flexibility plays a critical part in our ability to provide all customers reliable electric service.

Distribution Planning

On an annual basis, Distribution Planning conducts Substation Load and Capacity Analysis (SLACA) of the distribution system. This entails analysis of the previous year's substation transformer loading data—from our SCADA system, if available—to examine whether the highest peak load observed at the substation transformer violates distribution planning criteria. That is, a substation transformer shall have the capacity to not only accommodate the highest peak demand and any forecasted load growth, but also accommodate the load from the loss of a neighboring substation transformer—whether due to maintenance, equipment failure, or electrical fault—based upon the greater of the transformer loss-of-life rating, protective fuse rating, or cooling rating. Simply put, these ratings can be viewed as the thermal limit of the transformer. Failure to meet this criterion may result in overloaded equipment.

As discussed in the previous section, there are often multiple ties between circuits that provide system operators strategies to transfer or re-configure circuits to ensure a path to provide electric power service to customers. The SLACA analysis provides the system operators the confidence that at any point in the day, circuits may be re-configured to provide power during an abnormal or contingency situation. To better understand this concept, a rough rule of thumb can be applied; at peak load conditions, transformers are loaded to 50% of its rated capacity. In other words, a 50% transformer capacity reserve margin is maintained during normal circuit configurations or operations to ensure the operational flexibility of the system. This 50% reserve margin is then used to accommodate the load (or reverse power from PV) of a neighboring out-of-service substation transformer.

It is common for the configuration of the distribution system to change from year to year; this also affects PV hosting capacities. The following factors drive the dynamic nature of the distribution system: changing customer behavior, load growth, load imbalances, or degradation of power quality. Also, power quality is analyzed to ensure the appropriate standards are being met.

Upon completion of the SLACA analysis any planning criteria (including loss of operational flexibility) violations are addressed. Planners first seek the most efficient, least cost strategy. Permanently re-configuring a circuit by transferring load from a substation that exceeds the 50% capacity threshold to a neighboring substation that is loaded less than 50% represents a least cost solution that may restore operational flexibility. If least cost solutions fail to resolve the planning criteria violations, longer lead, more costly solutions are sought. Planners may order the construction of a new substation to create capacity. This type of solution is usually triggered based upon the 10-year load forecast that is updated each year and informed by the SLACA analysis. Load growth is determined by new customer service requests, economic or land development projections, and load trends. Unlike mainland utilities, the SLACA analysis is not completed seasonally. Hawai‘i does not see significant load variations between winter and summer months, nor do we benefit from increased capability of utility equipment due to cooler ambient temperatures.

Distribution Planning also performs similar capacity analysis on the sub-transmission system, utilizing a similar process to resolve any capacity issues.

Distributed Energy Resource Planning

Distributed Energy Resource (DER) planning and the exponential PV growth experienced within the last couple of years have evolved the traditional distribution planning process. We recently employed a process and methodology to perform hosting capacity analysis to more appropriately predict and plan for the integration of DG-PV. As shown in Figure N-39, almost 50% of the distribution circuits have more PV than the daytime minimum load; reverse flow is the new norm on our Hawai‘i grids. This is not the case for other systems throughout the United States.

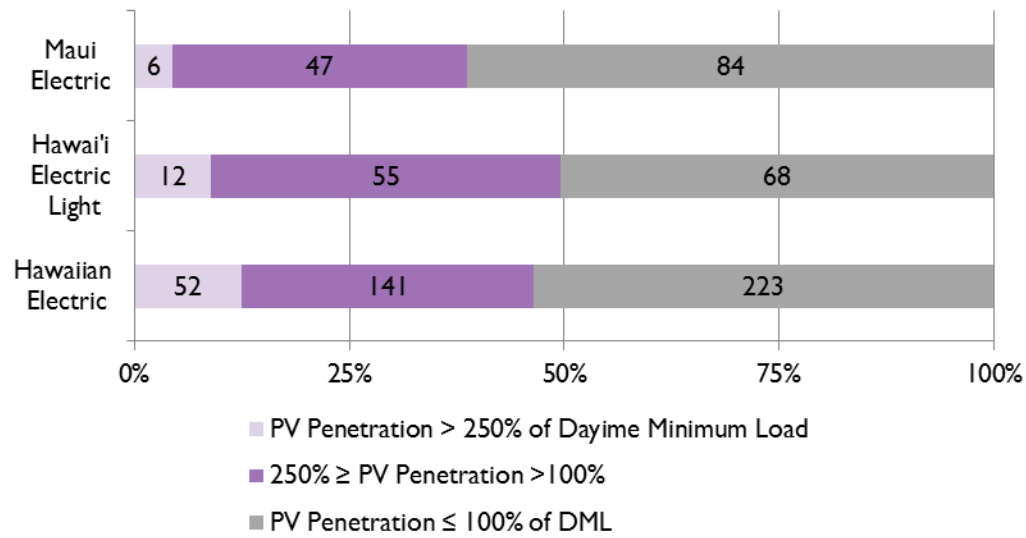

Figure N-39. Circuit PV Penetration in terms of Daytime Minimum Load

Based on previous high DG-PV penetration studies we have conducted coupled with field experience, the hosting capacity analysis evaluates (1) voltage quality, (2) equipment/wire capacity, and (3) operational flexibility. Undoubtedly, there are many more potential impacts that can affect the safety, reliability, and power quality of electric service to all of our customers, but these three issues are of the most immediate near-term concerns. As part of the hosting capacity analysis, an Operational Circuit Limit is also determined. This limit defines the reverse power threshold at the substation to maintain the operational flexibility of the circuit—the same principle described as part of the Distribution Planning process above.

A PV system's impact to a distribution system is highly dependent on its actual location with consideration of a number of factors: load, circuit impedance, neighboring PV systems. The hosting capacity analysis, through software simulation and analytics, determines the amount of PV a circuit can accommodate, regardless of location, before violating one of the three criteria discussed above. The interconnection of PV above that hosting capacity may incur capital improvements to mitigate any violations of the three hosting capacity criteria evaluated as part of the analysis. More details regarding the hosting capacity analysis can be found in the document titled, Rooftop PV Interconnections: A Methodology of Determining PV Circuit Hosting Capacity filed in Docket No. 2014-0192, on December 11, 2015.

As discussed in the preceding section, the distribution system is typically planned around the peak demand of a circuit. With the introduction of PV, distribution system planning must now account for minimum load, high generation periods in addition to the traditional evening peak period.

Under the net energy metering program, it was common practice for customers to size PV systems to offset their annual energy usage; the unintended technical consequence of this practice results in energy exports greater than the customer's typical peak load, which the distribution system was originally designed to accommodate. Consequently, during solar peak hours and daytime load levels, the peak export of energy onto the distribution system is greater in magnitude and more coincident than a customer's evening peak load. This increased power flow during minimum load periods will create power quality and capacity impacts that must be addressed before integrating high amounts of PV. Figure N-40 illustrates this point; a customer with the average 6 kW PV system is sized to zero-out his or her annual energy usage. This equates to an average monthly consumption of 806 kWh (531 kWh per weekdays per month). On a typical residential load profile, this energy usage equates to a peak demand of 2.3 kW. During daytime minimum loads, when this customer is assumed to be at work, the PV exports up to 4.5 kW. During daytime hours the load flow on the secondary part of the system is 4.5 kW, as opposed to its previous peak loading of 2.3 kW in the evening; nearly double the normal peak loading. This amount of exported energy exceeds any inherent design margins of the distribution system. A combination of smart energy management and circuit upgrades can restore the robustness of the distribution system.

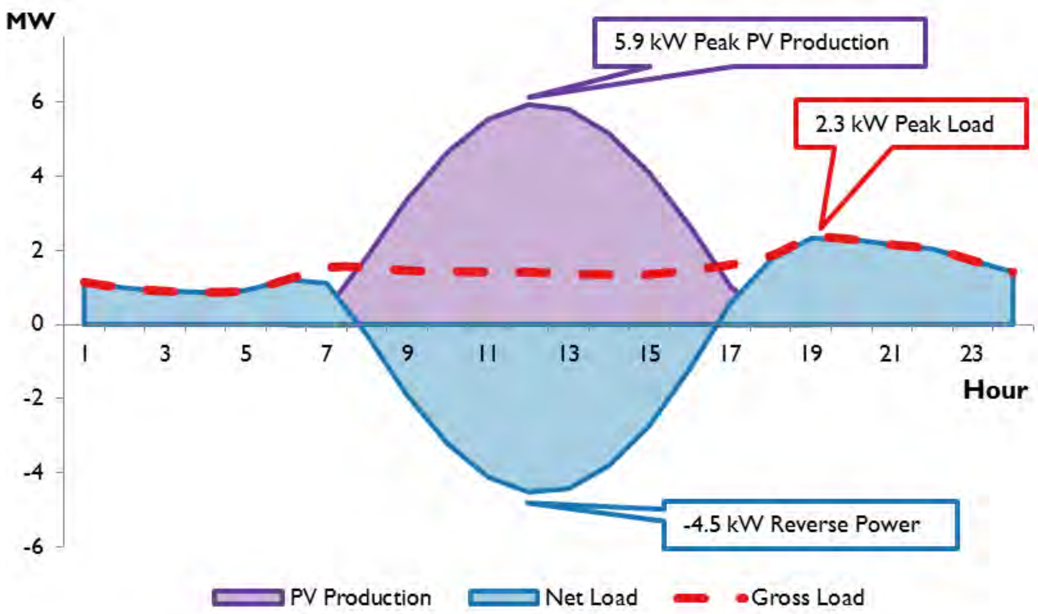

Figure N-40. Typical Weekday Residential Customer Load Profile with a 6 kW PV system sized to zero out annual consumption

The lack of PV production diversity as compared to the load diversity seen during the evening peak load creates PV integration challenges on the distribution system. Load diversity and the non-coincident behavior of customers allow distribution planners to plan the distribution system under peak demand conditions with certainty that customers will not simultaneously consume power at their peak; the distribution system is designed to accommodate diversified customer load—not the maximum potential load. For instance, a service transformer serving 10 homes typically has a diversity factor[14] as much as 45% In contrast, PV systems lack the same type of diversity as all PV production is a function of the sun's irradiance and not a function of diverse human behavior. Diversity from the placement, angle, and direction of a PV system equates to roughly 75-85% of the maximum capacity; not nearly the same overall reduction as load diversity. Put another way, the sun does not shine when customers are consuming the most electricity.

By necessity the hosting capacity analysis will develop into a more dynamic and granular analysis, as battery, electric vehicle, and the deployment of other distributed resources continue to grow. Battery standards that recognize a battery's unique characteristic of functioning as a load and generator will be established to create grid positive benefits; charging when the system most needs load, discharging when it most needs generation—in steady-state and transient conditions.

As the State continues to electrify transportation, electric vehicle charging should coincide with system needs as to not impress undue strain on utility equipment and operations. The dynamic hosting capacity models should integrate these behind the meter distributed energy resources to efficiently, design, plan, and operate the distribution grid.

DG-PV Forecasts by Distribution Circuits

DG-PV forecasts for all circuits on our three major grid are presented in Table N-5 through Table N-10 for Hawaiian Electric, Maui Electric, ad Hawaiʻi Electric Light circuits.

Legend: OCL = Operational Circuit Limit; HC = Posted Hosting Capacity

[14] Diversity factor is the ratio of actual coincient peak load to the sum of all customers' non-coincident peak peak load. For example, the total non-coincident peak load for 10 homes may be 100kW but at any given time the total loads that must be served by the utility 4.5kW. In other words, not all homes are running its water heater, oven, and other appliances at the same time.

Hawaiian Electric Distribution Circuit Base DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,044	5,137	1,119	1,372	1,432	1,479	1,522	1,803	2,170	2,170
Circuit 2	5,170	2,392	3,308	4,055	4,233	4,370	4,499	5,287	5,287	5,287
Circuit 3	5,692	484	961	1,178	1,229	1,269	1,307	1,547	1,884	2,085
Circuit 4	361	307	–	–	–	–	–	–	–	–
Circuit 5	4,770	3,284	3,163	3,877	4,047	4,179	4,302	5,094	6,201	6,523
Circuit 6	2,556	2,173	383	470	490	506	521	617	751	831
Circuit 7	1,198	1,019	148	181	189	195	201	217	217	217
Circuit 8	1,940	319	1,020	1,250	1,305	1,348	1,387	1,643	2,000	2,214
Circuit 9	1,301	951	1,041	1,276	1,332	1,375	1,416	1,677	2,041	2,058
Circuit 10	5,107	4,341	2,003	2,456	2,564	2,647	2,725	3,227	3,928	4,348
Circuit 11	689	585	–	–	–	–	–	–	–	–
Circuit 12	1,714	1,457	–	–	–	–	–	–	–	–
Circuit 13	6,272	5,331	154	188	196	203	209	247	301	333
Circuit 14	573	438	635	778	813	839	864	960	960	960
Circuit 15	5,750	4,887	3,480	4,266	4,454	4,598	4,734	5,606	6,824	7,553
Circuit 16	5,701	1,825	2,208	2,706	2,825	2,917	3,003	3,556	4,329	4,791
Circuit 17	5,699	4,605	2,659	3,259	3,402	3,513	3,616	4,282	5,213	5,677
Circuit 18	2,402	2,042	–	–	–	–	–	–	–	–
Circuit 19	3,003	2,553	–	–	–	–	–	–	–	–
Circuit 20	7,330	6,185	529	648	677	699	719	852	1,037	1,148
Circuit 21	5,331	4,499	178	218	228	235	242	287	349	386
Circuit 22	4,733	3,901	–	–	–	–	–	–	–	–
Circuit 23	6,741	5,747	1,055	1,293	1,350	1,393	1,434	1,699	2,068	2,289
Circuit 24	1,448	575	840	1,029	1,074	1,109	1,142	1,352	1,493	1,493
Circuit 25	7,601	4,006	2,933	3,595	3,753	3,875	3,989	4,724	5,750	6,365
Circuit 26	1,005	854	246	302	315	325	335	397	483	534
Circuit 27	771	465	568	696	727	750	772	915	1,113	1,233
Circuit 28	4,190	3,686	565	693	723	747	769	910	1,108	1,226
Circuit 29	4,187	3,386	3,514	4,308	4,497	4,643	4,780	5,660	6,296	6,296
Circuit 30	6,569	5,583	1,144	1,402	1,464	1,511	1,556	1,842	2,243	2,483
Circuit 31	5,359	4,555	1,151	1,411	1,473	1,520	1,565	1,565	1,565	1,565
Circuit 32	1,211	1,029	457	560	585	604	622	736	833	833
Circuit 33	3,114	1,758	–	–	–	–	–	–	–	–
Circuit 34	3,107	2,641	–	–	–	–	–	–	–	–
Circuit 35	6,611	5,619	2,025	2,482	2,591	2,675	2,754	2,777	2,777	2,777
Circuit 36	4,151	3,635	208	255	266	275	283	335	408	452

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	2,806	2,385	–	–	–	–	–	–	–	–
Circuit 38	4,488	3,737	273	334	349	361	371	439	535	592
Circuit 39	1,403	1,193	–	–	–	–	–	–	–	–
Circuit 40	1,873	249	1,865	2,286	2,387	2,464	2,537	2,673	2,673	2,673
Circuit 41	3,266	2,252	312	383	399	412	424	503	612	677
Circuit 42	3,126	2,657	–	–	–	–	–	–	–	–
Circuit 43	4,186	3,558	520	637	665	687	707	838	1,020	1,129
Circuit 44	5,293	1,234	283	347	362	374	385	455	554	614
Circuit 45	5,673	4,822	2,476	2,476	2,476	2,476	2,476	2,476	2,476	2,476
Circuit 46	1,380	1,161	1,074	1,316	1,374	1,419	1,460	1,666	1,666	1,666
Circuit 47	3,559	3,025	–	–	–	–	–	–	–	–
Circuit 48	4,529	3,850	–	–	–	–	–	–	–	–
Circuit 49	3,102	2,637	3,117	3,821	3,989	4,119	4,240	5,021	5,337	5,337
Circuit 50	5,323	4,426	2,909	3,566	3,722	3,843	3,956	4,685	5,703	5,913
Circuit 51	3,931	3,126	1,844	2,260	2,359	2,436	2,508	2,970	3,615	4,001
Circuit 52	4,736	2,867	2,292	2,809	2,932	3,028	3,117	3,691	4,493	4,973
Circuit 53	5,383	6,171	3,342	4,097	4,277	4,416	4,546	5,383	6,553	7,253
Circuit 54	4,830	4,355	3,074	3,768	3,870	3,870	3,870	3,870	3,870	3,870
Circuit 55	6,640	5,120	2,810	2,810	2,810	2,810	2,810	2,810	2,810	2,810
Circuit 56	2,289	1,001	763	935	976	1,007	1,037	1,228	1,495	1,655
Circuit 57	5,837	3,689	748	917	958	989	1,018	1,205	1,467	1,624
Circuit 58	3,014	2,562	4	4	5	5	5	6	7	8
Circuit 59	6,331	3,121	246	301	314	325	334	396	482	533
Circuit 60	3,667	3,117	338	415	433	447	460	545	663	734
Circuit 61	2,895	2,461	190	233	243	251	258	306	373	412
Circuit 62	4,599	4,180	2,446	2,998	3,130	3,231	3,326	3,939	4,795	5,308
Circuit 63	4,789	4,544	2,668	3,271	3,414	3,525	3,629	4,297	5,231	5,581
Circuit 64	4,747	4,445	4,837	5,929	6,021	6,021	6,021	6,021	6,021	6,021
Circuit 65	3,651	3,341	1,534	1,880	1,962	2,026	2,086	2,470	2,534	2,534
Circuit 66	3,366	2,861	1,786	2,189	2,285	2,359	2,429	2,876	3,498	3,498
Circuit 67	4,703	3,402	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370
Circuit 68	4,308	3,662	1,984	2,433	2,539	2,622	2,699	3,196	3,549	3,549
Circuit 69	5,586	4,100	2,163	2,651	2,768	2,858	2,942	3,484	4,241	4,694
Circuit 70	4,351	3,698	1,461	1,791	1,870	1,931	1,987	2,353	2,865	3,171
Circuit 71	8,420	7,157	3,285	4,027	4,204	4,340	4,468	5,291	6,441	7,130
Circuit 72	930	506	8	10	10	11	11	13	16	18
Circuit 73	5,289	4,496	2,955	3,622	3,781	3,904	4,019	4,759	5,793	6,412
Circuit 74	6,899	841	1,018	1,248	1,303	1,345	1,385	1,640	1,996	2,209

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	7,393	4,965	160	196	204	211	217	257	313	346
Circuit 76	3,528	2,999	–	–	–	–	–	–	–	–
Circuit 77	2,673	2,594	52	64	66	69	71	84	102	113
Circuit 78	7,301	1,140	3,048	3,737	3,901	4,027	4,146	4,910	5,936	5,936
Circuit 79	1,470	706	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894
Circuit 80	5,814	3,867	1,640	2,011	2,099	2,167	2,231	2,642	3,216	3,560
Circuit 81	5,352	3,730	2,687	3,294	3,439	3,551	3,655	4,328	5,269	5,832
Circuit 82	220	445	136	167	174	180	185	220	267	296
Circuit 83	1,968	1,673	904	904	904	904	904	904	904	904
Circuit 84	3,688	3,134	1,863	2,284	2,384	2,462	2,534	3,001	3,305	3,305
Circuit 85	5,288	4,495	1,168	1,431	1,494	1,543	1,588	1,881	2,289	2,534
Circuit 86	6,597	5,607	941	1,153	1,204	1,243	1,280	1,515	1,793	1,793
Circuit 87	5,113	5,647	2,759	3,382	3,530	3,645	3,752	4,443	4,758	4,758
Circuit 88	2,363	1,839	711	711	711	711	711	711	711	711
Circuit 89	2,488	2,419	1,052	1,290	1,347	1,390	1,430	1,430	1,430	1,430
Circuit 90	5,510	4,684	658	806	842	869	895	1,059	1,290	1,380
Circuit 91	1,351	474	593	727	759	784	807	956	1,163	1,288
Circuit 92	3,605	3,064	–	–	–	–	–	–	–	–
Circuit 93	2,416	1,356	1,537	1,884	1,966	2,030	2,090	2,466	2,466	2,466
Circuit 94	4,283	3,640	6	7	8	8	8	10	12	13
Circuit 95	6,936	5,896	3,372	3,372	3,372	3,372	3,372	3,372	3,372	3,372
Circuit 96	7,190	6,112	506	620	647	668	688	815	992	1,098
Circuit 97	7,570	6,435	–	–	–	–	–	–	–	–
Circuit 98	3,979	3,382	291	357	373	385	396	469	566	566
Circuit 99	13,437	10,102	–	–	–	–	–	–	–	–
Circuit 100	4,164	3,539	–	–	–	–	–	–	–	–
Circuit 101	4,381	3,724	3,140	3,849	4,018	4,149	4,271	5,058	6,157	6,527
Circuit 102	4,691	1,374	1,719	2,107	2,200	2,271	2,338	2,769	3,370	3,731
Circuit 103	6,866	5,836	1,490	1,826	1,907	1,969	2,026	2,358	2,358	2,358
Circuit 104	2,085	1,079	1,324	1,623	1,694	1,749	1,800	2,132	2,596	2,873
Circuit 105	1,609	1,367	891	1,092	1,140	1,178	1,212	1,435	1,559	1,559
Circuit 106	6,462	2,525	1,555	1,906	1,989	2,054	2,114	2,504	3,048	3,374
Circuit 107	1,905	816	1,225	1,502	1,568	1,619	1,667	1,974	2,163	2,163
Circuit 108	5,240	3,794	2,262	2,773	2,894	2,989	3,076	3,643	4,435	4,909
Circuit 109	4,903	1,667	1,747	2,142	2,236	2,309	2,377	2,814	3,426	3,792
Circuit 110	349	296	330	404	422	436	448	531	584	584
Circuit 111	1,287	678	782	958	1,000	1,033	1,063	1,259	1,425	1,425
Circuit 112	3,746	3,184	2,622	3,214	3,355	3,464	3,566	4,079	4,079	4,079

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 113	7,039	5,983	4,665	5,719	5,970	6,164	6,345	7,514	8,062	8,062
Circuit 114	5,755	4,892	3,272	4,011	4,187	4,323	4,450	5,270	6,416	7,101
Circuit 115	1,862	890	1,991	2,440	2,547	2,630	2,707	3,010	3,010	3,010
Circuit 116	1,393	697	905	1,110	1,158	1,196	1,231	1,458	1,775	1,861
Circuit 117	2,519	765	429	526	549	567	583	691	841	931
Circuit 118	430	700	6	8	8	8	9	10	12	14
Circuit 119	2,006	1,399	–	–	–	–	–	–	–	–
Circuit 120	4,969	3,214	320	392	410	423	435	516	628	695
Circuit 121	8,943	6,377	378	463	484	499	514	609	741	820
Circuit 122	2,169	1,102	873	1,070	1,117	1,153	1,187	1,405	1,711	1,847
Circuit 123	2,344	1,992	241	295	308	318	328	388	473	523
Circuit 124	4,831	4,107	–	–	–	–	–	–	–	–
Circuit 125	1,435	1,086	1,671	1,671	1,671	1,671	1,671	1,671	1,671	1,671
Circuit 126	6,644	4,806	–	–	–	–	–	–	–	–
Circuit 127	5,187	4,409	–	–	–	–	–	–	–	–
Circuit 128	1,604	1,364	415	509	532	549	565	669	815	902
Circuit 129	1,681	916	666	816	852	880	905	1,072	1,305	1,445
Circuit 130	1,352	1,086	343	420	439	453	467	552	673	744
Circuit 131	2,267	1,446	748	917	957	988	1,017	1,204	1,466	1,623
Circuit 132	2,449	2,082	518	518	2,018	2,018	3,518	3,518	3,518	3,518
Circuit 133	5,337	4,536	1,058	1,297	1,354	1,398	1,439	1,705	2,075	2,297
Circuit 134	2,267	1,002	911	1,117	1,166	1,204	1,239	1,467	1,786	1,977
Circuit 135	2,752	515	1,026	1,258	1,313	1,356	1,396	1,653	2,012	2,227
Circuit 136	4,602	2,088	600	736	768	793	816	840	840	840
Circuit 137	1,505	1,809	8	10	10	11	11	13	16	17
Circuit 138	5,753	5,889	1,214	1,488	1,554	1,604	1,651	1,956	2,381	2,635
Circuit 139	3,459	2,468	3,029	3,713	3,876	4,002	4,119	4,598	4,598	4,598
Circuit 140	3,856	3,863	773	948	990	1,022	1,052	1,246	1,516	1,679
Circuit 141	2,659	1,905	1,736	2,128	2,221	2,293	2,361	2,796	3,403	3,767
Circuit 142	2,792	2,539	998	998	998	998	998	998	998	998
Circuit 143	1,889	1,583	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
Circuit 144	8,363	7,109	600	736	768	793	816	966	1,176	1,302
Circuit 145	6,223	5,290	300	368	384	396	408	483	588	651
Circuit 146	6,528	5,549	2,207	2,706	2,825	2,916	3,002	3,555	4,328	4,790
Circuit 147	3,308	2,812	132	162	169	175	180	213	259	287
Circuit 148	2,783	2,366	1,694	2,076	2,167	2,238	2,304	2,728	3,321	3,676
Circuit 149	6,292	5,081	569	697	728	751	773	916	1,115	1,234
Circuit 150	2,983	2,028	272	334	348	360	370	439	470	470

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 151	5,020	4,267	2,519	3,088	3,223	3,328	3,426	4,057	4,618	4,618
Circuit 152	5,741	3,499	587	719	751	775	798	945	1,150	1,273
Circuit 153	4,106	2,067	232	284	296	306	315	373	454	503
Circuit 154	4,941	1,152	–	–	–	–	–	–	–	–
Circuit 155	5,774	4,908	–	–	–	–	–	–	–	–
Circuit 156	4,879	4,147	–	–	–	–	–	–	–	–
Circuit 157	3,629	3,084	87	87	87	87	87	87	87	87
Circuit 158	889	499	316	387	404	417	420	420	420	420
Circuit 159	2,132	984	589	722	754	778	801	949	1,155	1,278
Circuit 160	5,736	4,137	535	656	684	707	728	862	1,049	1,161
Circuit 161	6,310	4,551	1,246	1,527	1,594	1,646	1,694	2,007	2,443	2,704
Circuit 162	4,056	3,448	364	446	465	480	494	585	713	789
Circuit 163	1,911	1,624	206	208	208	208	208	208	208	208
Circuit 164	725	920	629	629	629	629	629	629	629	629
Circuit 165	1,877	1,595	–	–	–	–	–	–	–	–
Circuit 166	1,032	877	398	487	509	525	541	640	670	670
Circuit 167	5,120	4,352	578	709	740	764	786	931	1,133	1,254
Circuit 168	3,546	963	1,226	1,503	1,569	1,620	1,667	1,974	2,404	2,660
Circuit 169	4,029	2,935	3,628	4,447	4,643	4,794	4,935	5,623	5,623	5,623
Circuit 170	1,120	952	409	502	524	541	557	659	803	806
Circuit 171	4,969	3,827	248	304	318	328	338	400	487	539
Circuit 172	2,755	2,342	362	443	463	478	492	582	709	785
Circuit 173	624	531	442	442	442	442	442	442	442	442
Circuit 174	3,230	2,745	928	1,137	1,187	1,226	1,262	1,494	1,537	1,537
Circuit 175	7,927	5,784	692	848	885	914	941	1,114	1,356	1,501
Circuit 176	721	613	–	–	–	–	–	–	–	–
Circuit 177	4,497	3,822	1,617	1,982	2,069	2,136	2,199	2,604	2,747	2,747
Circuit 178	7,024	6,024	1,275	1,562	1,631	1,684	1,734	2,053	2,299	2,299
Circuit 179	3,851	3,052	115	141	147	151	156	185	225	249
Circuit 180	5,782	4,088	83	102	106	109	113	133	162	180
Circuit 181	83	62	–	–	–	–	–	–	–	–
Circuit 182	3,416	2,510	116	142	148	153	157	186	227	251
Circuit 183	11,185	9,507	500	613	640	661	680	805	980	1,085
Circuit 184	5,907	5,021	270	331	346	357	367	435	529	586
Circuit 185	6,299	5,354	1,945	2,384	2,489	2,570	2,646	3,133	3,557	3,557
Circuit 186	1,088	707	957	1,174	1,225	1,265	1,302	1,542	1,877	2,070
Circuit 187	3,487	2,964	355	435	454	469	483	572	696	771
Circuit 188	6,420	5,641	282	346	361	373	384	455	554	613

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 189	60	52	–	–	–	–	–	–	–	–
Circuit 190	4,546	3,864	–	–	–	–	–	–	–	–
Circuit 191	3,108	2,642	2,350	2,881	3,008	3,105	3,197	3,786	4,009	4,009
Circuit 192	1,030	450	635	778	812	838	863	1,022	1,244	1,377
Circuit 193	3,249	759	–	–	–	–	–	–	–	–
Circuit 194	4,897	4,163	1,897	2,325	2,427	2,506	2,580	2,874	2,874	2,874
Circuit 195	4,138	3,518	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373
Circuit 196	7,671	6,520	2,649	3,247	3,389	3,500	3,603	4,266	5,193	5,748
Circuit 197	10,634	9,039	4,440	5,443	5,682	5,867	6,040	7,152	8,053	8,053
Circuit 198	952	809	203	249	260	268	268	268	268	268
Circuit 199	4,410	3,749	1,676	2,054	2,145	2,214	2,280	2,699	3,154	3,154
Circuit 200	4,112	1,608	1,137	1,394	1,455	1,503	1,547	1,832	1,935	1,935
Circuit 201	4,019	3,416	2,551	3,127	3,264	3,370	3,470	4,109	4,697	4,697
Circuit 202	4,355	2,666	1,694	2,077	2,168	2,238	2,304	2,433	2,433	2,433
Circuit 203	505	430	87	107	111	115	118	140	144	144
Circuit 204	5,370	4,565	39	47	49	51	52	62	76	84
Circuit 205	983	835	–	–	–	–	–	–	–	–
Circuit 206	3,562	3,027	–	–	–	–	–	–	–	–
Circuit 207	4,274	3,083	58	71	74	76	78	93	113	125
Circuit 208	3,627	1,295	836	1,024	1,069	1,104	1,136	1,346	1,638	1,813
Circuit 209	1,711	1,454	545	668	697	720	741	878	1,069	1,118
Circuit 210	3,125	2,693	1,537	1,884	1,967	2,031	2,090	2,475	3,013	3,336
Circuit 211	6,616	5,808	3,213	3,938	4,111	4,245	4,370	5,175	6,300	6,973
Circuit 212	5,706	5,033	2,562	3,141	3,279	3,386	3,485	4,127	5,024	5,561
Circuit 213	1,903	1,471	1,139	1,396	1,457	1,505	1,549	1,834	2,233	2,471
Circuit 214	8,176	6,950	350	429	448	462	476	564	686	760
Circuit 215	5,354	3,717	1,590	1,949	2,035	2,101	2,163	2,561	2,780	2,780
Circuit 216	2,008	1,706	609	609	609	609	609	609	609	609
Circuit 217	5,447	4,630	1,120	1,373	1,433	1,480	1,523	1,804	2,196	2,431
Circuit 218	3,541	3,010	1,371	1,681	1,754	1,811	1,865	2,208	2,688	2,975
Circuit 219	179	152	–	–	–	–	–	–	–	–
Circuit 220	2,869	2,438	1,993	2,444	2,551	2,634	2,711	3,211	3,908	4,326
Circuit 221	6,009	4,641	1,722	2,111	2,204	2,276	2,343	2,774	3,377	3,738
Circuit 222	2,079	1,767	1,602	1,964	2,050	2,117	2,179	2,580	3,141	3,338
Circuit 223	5,005	2,998	907	1,112	1,160	1,198	1,233	1,461	1,778	1,968
Circuit 224	2,919	2,127	350	429	448	462	476	564	686	760
Circuit 225	8,145	6,776	863	1,058	1,105	1,141	1,174	1,391	1,693	1,874
Circuit 226	1,186	578	322	395	413	426	432	432	432	432

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 227	190	162	35	42	44	46	47	56	68	75
Circuit 228	2,419	676	917	1,124	1,173	1,211	1,247	1,477	1,797	1,990
Circuit 229	7,351	6,249	2,573	3,154	3,293	3,400	3,500	4,144	5,045	5,550
Circuit 230	4,579	3,892	1,027	1,259	1,315	1,357	1,397	1,655	2,014	2,230
Circuit 231	2,090	1,777	599	735	767	792	815	965	1,175	1,301
Circuit 232	4,899	4,237	96	118	123	127	131	155	188	208
Circuit 233	7,858	4,263	2,930	3,591	3,749	3,871	3,985	4,719	5,744	6,358
Circuit 234	1,663	1,532	294	361	377	389	400	474	577	639
Circuit 235	5,011	4,027	2,338	2,866	2,916	2,916	2,916	2,916	2,916	2,916
Circuit 236	8,704	4,964	3,984	4,884	5,098	5,264	5,419	6,417	7,193	7,193
Circuit 237	4,312	4,027	2,592	3,177	3,316	3,424	3,525	4,174	5,081	5,615
Circuit 238	748	717	958	958	958	958	958	958	958	958
Circuit 239	3,566	3,031	1,897	2,326	2,428	2,507	2,580	3,056	3,720	4,118
Circuit 240	4,602	4,036	2	3	3	3	3	4	5	5
Circuit 241	8,243	6,839	2,600	2,833	2,833	2,833	2,833	2,833	2,833	2,833
Circuit 242	1,597	1,256	365	447	467	482	496	588	715	792
Circuit 243	177	2,344	–	–	–	–	–	–	–	–
Circuit 244	2,979	3,794	679	832	868	897	923	1,093	1,330	1,473
Circuit 245	5,261	3,543	2,168	2,658	2,775	2,865	2,949	3,492	4,251	4,387
Circuit 246	711	226	–	–	–	–	–	–	–	–
Circuit 247	4,259	3,857	438	537	560	578	596	705	858	950
Circuit 248	4,452	793	1,099	1,347	1,406	1,452	1,494	1,770	1,945	1,945
Circuit 249	3,632	432	228	280	292	302	310	368	448	495
Circuit 250	2,345	1,993	1,140	1,397	1,459	1,506	1,550	1,836	2,166	2,166
Circuit 251	8,975	5,107	8,105	9,935	10,372	10,709	11,024	12,473	12,473	12,473
Circuit 252	2,897	963	1,507	1,847	1,928	1,990	2,049	2,426	2,664	2,664
Circuit 253	108	92	–	–	–	–	–	–	–	–
Circuit 254	7,195	6,288	585	717	748	773	795	942	1,147	1,269
Circuit 255	5,548	5,328	536	657	686	709	729	864	1,052	1,164
Circuit 256	3,836	3,624	726	890	930	960	988	1,170	1,424	1,576
Circuit 257	5,354	5,059	1,474	1,807	1,886	1,947	2,005	2,374	2,890	3,199
Circuit 258	5,212	2,335	4,705	5,768	6,021	6,217	6,400	7,579	9,226	10,212
Circuit 259	3,216	2,781	6,168	7,561	7,893	8,150	8,390	8,838	8,838	8,838
Circuit 260	8,148	5,689	4,628	5,673	5,922	6,115	6,294	7,454	9,074	10,044
Circuit 261	4,605	3,914	2,195	2,691	2,809	2,901	2,986	3,536	4,304	4,636
Circuit 262	5,475	4,654	1,483	1,818	1,898	1,960	2,017	2,389	2,812	2,812
Circuit 263	3,763	3,199	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552
Circuit 264	5,762	4,898	4,075	4,173	4,173	4,173	4,173	4,173	4,173	4,173

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 265	5,107	3,907	762	934	975	1,007	1,036	1,227	1,494	1,653
Circuit 266	3,937	3,346	182	223	233	240	247	293	357	395
Circuit 267	2,933	2,493	471	578	603	623	641	650	650	650
Circuit 268	6,033	5,128	1,623	1,989	2,077	2,144	2,207	2,614	3,182	3,522
Circuit 269	4,641	3,945	–	–	–	–	–	–	–	–
Circuit 270	4,421	3,758	1,116	1,368	1,428	1,474	1,518	1,797	2,009	2,009
Circuit 271	4,171	3,545	2,511	3,078	3,213	3,317	3,415	4,044	4,577	4,577
Circuit 272	1,154	981	495	607	633	654	673	797	970	1,074
Circuit 273	2,143	1,822	457	561	585	604	622	737	897	973
Circuit 274	2,946	2,504	1,520	1,864	1,946	2,009	2,068	2,449	2,925	2,925
Circuit 275	7,570	5,984	3,619	4,437	4,632	4,782	4,923	4,931	4,931	4,931
Circuit 276	3,122	3,475	4,129	4,129	4,129	4,129	4,129	4,129	4,129	4,129
Circuit 277	4,614	4,103	2,334	2,862	2,987	3,084	3,175	3,760	4,577	5,067
Circuit 278	4,340	3,953	2,186	2,680	2,798	2,888	2,973	3,521	4,286	4,690
Circuit 279	1,177	1,057	986	1,208	1,261	1,302	1,341	1,588	1,933	2,139
Circuit 280	2,936	2,495	897	1,099	1,147	1,185	1,220	1,444	1,758	1,946
Circuit 281	1,316	772	1,169	1,433	1,496	1,545	1,590	1,883	2,032	2,032
Circuit 282	4,214	780	1,137	1,394	1,455	1,502	1,546	1,831	2,229	2,468
Circuit 283	3,839	2,871	1,028	1,260	1,315	1,358	1,398	1,656	2,015	2,231
Circuit 284	2,299	1,954	1,798	2,204	2,300	2,375	2,445	2,895	3,520	3,520
Circuit 285	5,662	1,636	2,961	3,630	3,789	3,912	4,027	4,769	5,806	6,427
Circuit 286	5,271	4,480	33	41	43	44	45	54	66	73
Circuit 287	3,252	2,048	1,978	2,425	2,531	2,614	2,691	3,186	3,399	3,399
Circuit 288	9,600	3,270	3,026	3,709	3,872	3,998	4,115	4,874	5,338	5,338
Circuit 289	2,667	3,617	265	325	339	350	360	427	520	575
Circuit 290	2,772	1,028	1,170	1,434	1,497	1,546	1,592	1,885	2,294	2,540
Circuit 291	4,820	3,749	968	1,187	1,239	1,280	1,317	1,560	1,899	2,102
Circuit 292	5,222	2,086	970	1,189	1,242	1,282	1,320	1,563	1,903	2,106
Circuit 293	5,768	4,903	1,383	1,695	1,769	1,827	1,881	2,227	2,711	3,001
Circuit 294	6,307	3,281	767	940	981	1,013	1,043	1,235	1,503	1,664
Circuit 295	4,017	3,617	328	403	420	434	447	529	644	713
Circuit 296	4,136	2,357	412	505	527	545	561	664	808	895
Circuit 297	3,545	1,694	1,575	1,931	2,015	2,081	2,142	2,537	2,795	2,795
Circuit 298	4,054	3,446	2,444	2,996	3,128	3,230	3,325	3,937	4,507	4,507
Circuit 299	6,304	3,496	844	1,035	1,080	1,115	1,148	1,360	1,655	1,832
Circuit 300	4,455	1,469	1,791	2,195	2,292	2,366	2,436	2,885	3,512	3,887
Circuit 301	1,053	496	484	593	619	639	658	779	948	1,050
Circuit 302	4,019	3,416	1,763	2,161	2,256	2,329	2,397	2,839	3,456	3,825

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 303	6,695	3,596	4,674	5,729	5,981	6,175	6,357	7,528	9,164	9,263
Circuit 304	2,526	2,147	1,365	1,673	1,747	1,798	1,798	1,798	1,798	1,798
Circuit 305	1,852	740	964	1,182	1,234	1,274	1,312	1,553	1,891	2,093
Circuit 306	2,635	1,809	68	83	87	90	92	109	133	147
Circuit 307	4,943	4,202	2,091	2,563	2,676	2,763	2,844	3,368	4,100	4,337
Circuit 308	1,236	1,051	1,080	1,324	1,382	1,427	1,469	1,574	1,574	1,574
Circuit 309	1,140	714	469	575	600	620	638	755	920	928
Circuit 310	6,808	5,787	465	569	594	614	632	748	911	1,008
Circuit 311	6,285	5,342	460	564	589	608	626	741	902	998
Circuit 312	3,034	2,579	–	–	–	–	–	–	–	–
Circuit 313	3,923	2,934	1,799	2,206	2,303	2,377	2,447	2,898	3,484	3,484
Circuit 314	5,183	4,405	1,612	1,976	2,063	2,130	2,192	2,353	2,353	2,353
Circuit 315	3,086	2,623	489	599	626	646	665	788	959	1,061
Circuit 316	1,536	1,305	265	325	339	350	361	427	520	575
Circuit 317	5,006	3,868	48	59	62	64	65	78	94	104
Circuit 318	5,261	3,540	216	265	276	285	294	348	424	469
Circuit 319	4,865	4,135	349	428	447	462	475	563	685	758
Circuit 320	5,762	2,253	2,266	2,778	2,900	2,994	3,082	3,650	4,010	4,010
Circuit 321	337	287	79	96	101	104	107	127	154	171
Circuit 322	4,669	4,724	747	916	956	987	1,016	1,204	1,465	1,620
Circuit 323	144	123	–	–	–	–	–	–	–	–
Circuit 324	5,894	5,010	2,371	2,371	2,371	2,371	2,371	2,371	2,371	2,371
Circuit 325	608	588	501	615	642	662	682	808	983	1,081
Circuit 326	1,410	762	858	1,052	1,098	1,133	1,167	1,382	1,682	1,862
Circuit 327	1,463	511	1,311	1,311	1,311	1,311	1,311	1,311	1,311	1,311
Circuit 328	6,119	5,201	3,099	3,799	3,966	4,095	4,216	4,992	5,819	5,819
Circuit 329	1,610	1,369	1,053	1,290	1,347	1,391	1,432	1,695	2,055	2,055
Circuit 330	5,881	4,999	3,528	4,325	4,515	4,661	4,798	5,127	5,127	5,127
Circuit 331	924	785	95	116	121	125	129	152	186	205
Circuit 332	7,351	3,171	3,679	4,510	4,708	4,861	5,004	5,926	7,214	7,985
Circuit 333	5,964	5,069	1,020	1,250	1,305	1,347	1,387	1,642	1,999	2,213
Circuit 334	2,507	2,131	479	587	613	633	652	772	940	1,040
Circuit 335	3,598	3,058	1,369	1,369	1,369	1,369	1,369	1,369	1,369	1,369
Circuit 336	5,827	4,953	2,046	2,508	2,619	2,704	2,783	2,945	2,945	2,945
Circuit 337	3,697	3,143	1,061	1,301	1,358	1,402	1,444	1,710	2,081	2,304
Circuit 338	959	815	204	204	204	204	204	204	204	204
Circuit 339	9,020	7,667	2,362	2,647	2,647	2,647	2,647	2,647	2,647	2,647
Circuit 340	3,646	3,099	1,452	1,780	1,858	1,918	1,974	2,338	2,846	3,151

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 341	746	634	–	–	–	–	–	–	–	–
Circuit 342	4,140	1,454	1,864	2,286	2,386	2,463	2,536	3,003	3,656	4,046
Circuit 343	5,806	4,935	2,484	3,045	3,178	3,282	3,378	4,001	4,326	4,326
Circuit 344	4,257	3,619	1,738	2,131	2,225	2,297	2,364	2,367	2,367	2,367
Circuit 345	9,447	6,464	738	905	944	975	1,004	1,189	1,447	1,602
Circuit 346	4,257	3,619	1,580	1,937	2,022	2,088	2,150	2,546	3,099	3,251
Circuit 347	6,038	3,233	2,664	3,266	3,409	3,520	3,623	4,291	5,223	5,700
Circuit 348	3,111	1,014	1,179	1,446	1,509	1,558	1,604	1,899	2,312	2,559
Circuit 349	419	356	473	580	605	625	643	761	927	1,026
Circuit 350	6,149	3,240	2,547	3,123	3,260	3,366	3,465	4,103	4,995	5,529
Circuit 351	3,133	2,663	–	–	–	–	–	–	–	–
Circuit 352	2,391	1,567	44	44	44	44	44	44	44	44
Circuit 353	7,969	5,222	–	–	–	–	–	–	–	–
Circuit 354	6,602	5,612	24	29	31	32	33	39	47	52
Circuit 355	6,104	5,188	121	149	155	160	165	195	238	263
Circuit 356	3,888	3,304	46	56	59	61	63	74	90	100
Circuit 357	4,256	3,618	–	–	–	–	–	–	–	–
Circuit 358	2,982	2,535	1,070	1,312	1,369	1,414	1,455	1,724	2,098	2,322
Circuit 359	6,054	949	3,858	4,730	4,937	5,098	5,248	6,214	7,565	8,374
Circuit 360	1,341	513	595	595	595	595	595	595	595	595
Circuit 361	277	122	151	151	151	151	151	151	151	151
Circuit 362	6,306	5,364	1,308	1,604	1,674	1,729	1,780	2,107	2,565	2,840
Circuit 363	4,376	3,725	1,679	2,053	2,053	2,053	2,053	2,053	2,053	2,053
Circuit 364	5,368	4,562	3,881	4,757	4,966	5,127	5,278	6,185	6,185	6,185
Circuit 365	4,712	2,283	1,561	1,914	1,998	2,063	2,124	2,515	3,061	3,388
Circuit 366	4,162	1,910	1,120	1,373	1,434	1,480	1,524	1,805	2,197	2,432
Circuit 367	2,068	1,758	1,173	1,438	1,501	1,550	1,595	1,889	2,299	2,545
Circuit 368	4,623	1,336	1,540	1,887	1,970	2,034	2,094	2,480	3,019	3,342
Circuit 369	5,678	4,380	2,925	3,585	3,743	3,864	3,978	4,711	5,734	6,347
Circuit 370	3,020	524	526	645	674	695	716	848	1,032	1,142
Circuit 371	4,080	913	2,136	2,618	2,733	2,822	2,905	3,440	4,188	4,635
Circuit 372	5,743	4,882	3,688	4,521	4,720	4,873	5,016	5,940	7,138	7,138
Circuit 373	7,141	5,038	4,995	6,123	6,392	6,600	6,794	8,045	8,421	8,421
Circuit 374	4,249	3,612	1,302	1,596	1,666	1,720	1,770	2,096	2,233	2,233
Circuit 375	4,040	3,434	754	924	965	996	1,026	1,215	1,479	1,623
Circuit 376	1,431	1,216	847	1,039	1,084	1,120	1,153	1,208	1,208	1,208
Circuit 377	1,821	717	1,084	1,328	1,387	1,432	1,474	1,745	2,124	2,222
Circuit 378	308	262	37	37	37	37	37	37	37	37

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 379	3,073	2,069	1,454	1,782	1,860	1,921	1,977	2,341	2,850	3,155
Circuit 380	1,552	1,319	1,666	2,042	2,131	2,201	2,265	2,683	2,699	2,699
Circuit 381	1,106	640	907	1,112	1,161	1,199	1,234	1,461	1,779	1,969
Circuit 382	–	–	40,100	49,157	51,315	52,983	54,542	64,588	78,625	87,030

Table N-5. Hawaiian Electric Distribution Circuit Base DG-PV Forecast (kW)

Hawaiian Electric Distribution Circuit High DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,044	5,137	1,119	1,282	1,402	1,453	1,506	2,547	3,634	3,634
Circuit 2	5,170	2,392	3,308	3,789	4,143	4,294	4,450	6,752	6,752	6,752
Circuit 3	5,692	484	961	1,101	1,203	1,247	1,293	2,186	3,127	3,598
Circuit 4	361	307	–	–	–	–	–	–	–	–
Circuit 5	4,770	3,284	3,163	3,623	3,961	4,106	4,255	7,196	7,987	7,987
Circuit 6	2,556	2,173	383	439	480	497	515	871	1,247	1,434
Circuit 7	1,198	1,019	148	169	185	192	199	336	481	553
Circuit 8	1,940	319	1,020	1,168	1,277	1,324	1,372	2,320	3,320	3,819
Circuit 9	1,301	951	1,041	1,193	1,304	1,352	1,401	2,369	3,389	3,523
Circuit 10	5,107	4,341	2,003	2,295	2,509	2,601	2,695	4,558	6,521	7,502
Circuit 11	689	585	–	–	–	–	–	–	–	–
Circuit 12	1,714	1,457	–	–	–	–	–	–	–	–
Circuit 13	6,272	5,331	154	176	192	199	207	349	500	575
Circuit 14	573	438	635	727	795	825	854	1,445	2,067	2,378
Circuit 15	5,750	4,887	3,480	3,987	4,359	4,519	4,683	7,918	11,328	13,033
Circuit 16	5,701	1,825	2,208	2,529	2,765	2,866	2,970	5,023	7,186	7,297
Circuit 17	5,699	4,605	2,659	3,045	3,330	3,452	3,577	6,049	7,141	7,141
Circuit 18	2,402	2,042	–	–	–	–	–	–	–	–
Circuit 19	3,003	2,553	–	–	–	–	–	–	–	–
Circuit 20	7,330	6,185	529	606	662	687	712	1,203	1,721	1,981
Circuit 21	5,331	4,499	178	204	223	231	239	405	579	667
Circuit 22	4,733	3,901	–	–	–	–	–	–	–	–
Circuit 23	6,741	5,747	1,055	1,208	1,321	1,369	1,419	2,399	3,433	3,950
Circuit 24	1,448	575	840	962	1,051	1,090	1,130	1,910	2,733	2,957
Circuit 25	7,601	4,006	2,933	3,359	3,673	3,808	3,946	6,672	8,143	8,143
Circuit 26	1,005	854	246	282	308	320	331	560	801	922
Circuit 27	771	465	568	651	711	737	764	1,292	1,849	2,127
Circuit 28	4,190	3,686	565	647	708	734	760	1,286	1,839	1,874
Circuit 29	4,187	3,386	3,514	4,026	4,402	4,563	4,728	7,760	7,760	7,760
Circuit 30	6,569	5,583	1,144	1,310	1,433	1,485	1,539	2,603	3,723	4,284
Circuit 31	5,359	4,555	1,151	1,318	1,441	1,494	1,548	2,618	3,029	3,029
Circuit 32	1,211	1,029	457	524	573	594	615	1,040	1,488	1,712
Circuit 33	3,114	1,758	–	–	–	–	–	–	–	–
Circuit 34	3,107	2,641	–	–	–	–	–	–	–	–
Circuit 35	6,611	5,619	2,025	2,319	2,536	2,629	2,724	4,006	4,006	4,006

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 36	4,151	3,635	208	239	261	270	280	474	678	780
Circuit 37	2,806	2,385	–	–	–	–	–	–	–	–
Circuit 38	4,488	3,737	273	313	342	354	367	621	888	1,022
Circuit 39	1,403	1,193	–	–	–	–	–	–	–	–
Circuit 40	1,873	249	1,865	2,137	2,336	2,422	2,510	4,137	4,137	4,137
Circuit 41	3,266	2,252	312	357	391	405	420	710	1,016	1,169
Circuit 42	3,126	2,657	–	–	–	–	–	–	–	–
Circuit 43	4,186	3,558	520	596	651	675	700	1,183	1,410	1,410
Circuit 44	5,293	1,234	283	324	354	367	380	643	920	1,059
Circuit 45	5,673	4,822	2,476	2,476	2,476	2,476	2,476	2,476	2,476	2,476
Circuit 46	1,380	1,161	1,074	1,230	1,345	1,394	1,445	2,443	3,130	3,130
Circuit 47	3,559	3,025	–	–	–	–	–	–	–	–
Circuit 48	4,529	3,850	–	–	–	–	–	–	–	–
Circuit 49	3,102	2,637	3,117	3,571	3,905	4,047	4,194	6,801	6,801	6,801
Circuit 50	5,323	4,426	2,909	3,332	3,643	3,777	3,914	6,618	7,377	7,377
Circuit 51	3,931	3,126	1,844	2,112	2,309	2,394	2,481	4,195	6,001	6,904
Circuit 52	4,736	2,867	2,292	2,625	2,870	2,975	3,083	5,214	7,459	7,938
Circuit 53	5,383	6,171	3,342	3,828	4,186	4,339	4,497	7,604	9,635	9,635
Circuit 54	4,830	4,355	3,074	3,521	3,850	3,991	4,135	5,335	5,335	5,335
Circuit 55	6,640	5,120	2,810	2,810	2,810	2,810	2,810	2,810	2,810	2,810
Circuit 56	2,289	1,001	763	873	955	990	1,026	1,735	2,482	2,856
Circuit 57	5,837	3,689	748	857	937	972	1,007	1,703	2,436	2,451
Circuit 58	3,014	2,562	4	4	5	5	5	8	12	14
Circuit 59	6,331	3,121	246	281	308	319	331	559	564	564
Circuit 60	3,667	3,117	338	387	424	439	455	769	1,101	1,267
Circuit 61	2,895	2,461	190	218	238	247	256	432	618	712
Circuit 62	4,599	4,180	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446
Circuit 63	4,789	4,544	2,668	3,056	3,342	3,464	3,590	6,070	7,046	7,046
Circuit 64	4,747	4,445	4,837	5,541	6,058	6,280	6,508	7,472	7,472	7,472
Circuit 65	3,651	3,341	1,534	1,757	1,921	1,991	2,063	3,489	3,999	3,999
Circuit 66	3,366	2,861	1,786	2,046	2,237	2,318	2,403	4,063	4,962	4,962
Circuit 67	4,703	3,402	2,370	2,715	2,969	3,077	3,189	3,347	3,347	3,347
Circuit 68	4,308	3,662	1,984	2,273	2,485	2,576	2,670	4,515	4,895	4,895
Circuit 69	5,586	4,100	2,163	2,478	2,709	2,808	2,910	4,921	7,040	7,348
Circuit 70	4,351	3,698	1,461	1,674	1,830	1,897	1,966	3,324	4,756	5,472
Circuit 71	8,420	7,157	3,285	3,763	4,115	4,265	4,420	7,474	10,693	12,302
Circuit 72	930	506	8	9	10	11	11	19	27	31
Circuit 73	5,289	4,496	2,955	3,384	3,701	3,836	3,975	6,722	8,100	8,100

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 74	6,899	841	1,018	1,166	1,275	1,322	1,370	2,316	3,313	3,812
Circuit 75	7,393	4,965	160	183	200	207	215	363	519	597
Circuit 76	3,528	2,999	–	–	–	–	–	–	–	–
Circuit 77	2,673	2,594	52	60	65	67	70	118	169	195
Circuit 78	7,301	1,140	3,048	3,492	3,818	3,958	4,101	6,935	7,400	7,400
Circuit 79	1,470	706	1,894	2,170	2,372	2,459	2,548	3,241	3,241	3,241
Circuit 80	5,814	3,867	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Circuit 81	5,352	3,730	2,687	3,078	3,366	3,489	3,616	6,114	8,182	8,182
Circuit 82	220	445	136	156	171	177	183	310	444	510
Circuit 83	1,968	1,673	904	1,036	1,132	1,174	1,216	2,057	2,060	2,060
Circuit 84	3,688	3,134	1,863	2,134	2,334	2,419	2,507	4,239	4,769	4,769
Circuit 85	5,288	4,495	1,168	1,338	1,463	1,516	1,571	2,657	3,801	4,041
Circuit 86	6,597	5,607	941	1,078	1,178	1,222	1,266	1,793	1,793	1,793
Circuit 87	5,113	5,647	2,759	3,160	3,455	3,582	3,712	6,223	6,223	6,223
Circuit 88	2,363	1,839	711	815	891	924	957	1,619	2,060	2,060
Circuit 89	2,488	2,419	1,052	1,205	1,318	1,366	1,416	2,394	2,895	2,895
Circuit 90	5,510	4,684	658	753	824	854	885	1,496	2,141	2,463
Circuit 91	1,351	474	593	680	743	770	798	1,350	1,932	2,222
Circuit 92	3,605	3,064	–	–	–	–	–	–	–	–
Circuit 93	2,416	1,356	1,537	1,760	1,925	1,995	2,068	3,496	3,706	3,706
Circuit 94	4,283	3,640	6	7	8	8	8	14	20	22
Circuit 95	6,936	5,896	3,372	3,372	3,372	3,372	3,372	3,372	3,372	3,372
Circuit 96	7,190	6,112	506	579	634	657	681	1,151	1,647	1,894
Circuit 97	7,570	6,435	–	–	–	–	–	–	–	–
Circuit 98	3,979	3,382	291	334	365	378	392	566	566	566
Circuit 99	13,437	10,102	–	–	–	–	–	–	–	–
Circuit 100	4,164	3,539	–	–	–	–	–	–	–	–
Circuit 101	4,381	3,724	3,140	3,597	3,933	4,077	4,225	7,144	7,992	7,992
Circuit 102	4,691	1,374	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719
Circuit 103	6,866	5,836	1,490	1,707	1,866	1,934	2,005	3,390	3,772	3,772
Circuit 104	2,085	1,079	1,324	1,516	1,658	1,719	1,781	3,012	4,309	4,957
Circuit 105	1,609	1,367	891	1,021	1,116	1,157	1,199	2,028	2,901	3,023
Circuit 106	6,462	2,525	1,555	1,781	1,947	2,018	2,092	3,537	5,060	5,411
Circuit 107	1,905	816	1,225	1,404	1,535	1,591	1,649	2,788	3,628	3,628
Circuit 108	5,240	3,794	2,262	2,591	2,833	2,937	3,043	5,146	7,362	7,598
Circuit 109	4,903	1,667	1,747	2,002	2,188	2,269	2,351	3,975	5,687	6,202
Circuit 110	349	296	330	378	413	428	443	750	1,073	1,234
Circuit 111	1,287	678	782	895	979	1,015	1,052	1,779	2,545	2,889

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 112	3,746	3,184	2,622	3,004	3,284	3,404	3,528	5,543	5,543	5,543
Circuit 113	7,039	5,983	4,665	5,344	5,843	6,057	6,277	9,526	9,526	9,526
Circuit 114	5,755	4,892	3,272	3,748	4,098	4,248	4,403	7,444	9,977	9,977
Circuit 115	1,862	890	1,991	2,280	2,493	2,584	2,678	4,474	4,474	4,474
Circuit 116	1,393	697	905	1,037	1,134	1,175	1,218	2,059	2,946	3,325
Circuit 117	2,519	765	429	491	537	557	577	976	1,396	1,606
Circuit 118	430	700	6	7	8	8	9	14	21	24
Circuit 119	2,006	1,399	–	–	–	–	–	–	–	–
Circuit 120	4,969	3,214	320	367	401	416	431	728	1,042	1,199
Circuit 121	8,943	6,377	378	433	473	491	508	860	958	958
Circuit 122	2,169	1,102	873	1,000	1,093	1,133	1,174	1,985	2,840	3,268
Circuit 123	2,344	1,992	241	276	302	313	324	548	784	903
Circuit 124	4,831	4,107	–	–	–	–	–	–	–	–
Circuit 125	1,435	1,086	1,671	1,914	2,093	2,170	2,248	2,895	2,895	2,895
Circuit 126	6,644	4,806	–	–	–	–	–	–	–	–
Circuit 127	5,187	4,409	–	–	–	–	–	–	–	–
Circuit 128	1,604	1,364	415	476	520	539	559	945	1,352	1,556
Circuit 129	1,681	916	666	763	834	864	896	1,515	2,167	2,493
Circuit 130	1,352	1,086	343	393	430	445	462	780	1,116	1,285
Circuit 131	2,267	1,446	748	857	937	971	1,006	1,701	2,434	2,800
Circuit 132	2,449	2,082	518	593	649	673	697	1,179	1,464	1,464
Circuit 133	5,337	4,536	1,058	1,212	1,326	1,374	1,424	2,408	3,445	3,508
Circuit 134	2,267	1,002	911	1,044	1,141	1,183	1,226	2,073	2,966	3,412
Circuit 135	2,752	515	1,026	1,176	1,285	1,332	1,381	2,335	3,341	3,843
Circuit 136	4,602	2,088	600	687	752	779	807	–	–	–
Circuit 137	1,505	1,809	8	9	10	10	11	18	26	30
Circuit 138	5,753	5,889	1,214	1,391	1,521	1,576	1,634	2,762	3,682	3,682
Circuit 139	3,459	2,468	3,029	3,469	3,793	3,932	4,075	6,063	6,063	6,063
Circuit 140	3,856	3,863	773	886	969	1,004	1,041	1,760	2,517	2,896
Circuit 141	2,659	1,905	1,736	1,988	2,174	2,253	2,335	3,949	5,649	6,500
Circuit 142	2,792	2,539	998	1,143	1,250	1,296	1,343	1,467	1,467	1,467
Circuit 143	1,889	1,583	1,488	1,705	1,733	1,733	1,733	1,733	1,733	1,733
Circuit 144	8,363	7,109	600	687	752	779	807	1,365	1,953	2,247
Circuit 145	6,223	5,290	300	344	376	390	404	683	976	1,123
Circuit 146	6,528	5,549	2,207	2,528	2,765	2,866	2,970	5,022	6,797	6,797
Circuit 147	3,308	2,812	132	151	166	172	178	301	430	495
Circuit 148	2,783	2,366	1,694	1,940	2,121	2,199	2,279	3,854	5,513	5,727
Circuit 149	6,292	5,081	569	651	712	738	765	1,294	1,851	2,129

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 150	2,983	2,028	272	312	341	354	366	470	470	470
Circuit 151	5,020	4,267	2,519	2,886	3,155	3,270	3,389	5,731	6,082	6,082
Circuit 152	5,741	3,499	587	672	735	762	789	1,335	1,910	2,197
Circuit 153	4,106	2,067	232	265	290	301	312	527	754	867
Circuit 154	4,941	1,152	–	–	–	–	–	–	–	–
Circuit 155	5,774	4,908	–	–	–	–	–	–	–	–
Circuit 156	4,879	4,147	–	–	–	–	–	–	–	–
Circuit 157	3,629	3,084	87	87	87	87	87	87	87	87
Circuit 158	889	499	316	362	395	410	425	718	1,028	1,182
Circuit 159	2,132	984	589	675	738	765	792	1,340	1,917	2,206
Circuit 160	5,736	4,137	535	613	670	694	720	1,217	1,741	2,003
Circuit 161	6,310	4,551	1,246	1,427	1,560	1,617	1,676	2,834	3,989	3,989
Circuit 162	4,056	3,448	364	416	455	472	489	827	1,159	1,159
Circuit 163	1,911	1,624	206	208	208	208	208	208	208	208
Circuit 164	725	920	629	720	788	816	846	1,431	1,467	1,467
Circuit 165	1,877	1,595	–	–	–	–	–	–	–	–
Circuit 166	1,032	877	398	455	498	516	535	904	1,294	1,489
Circuit 167	5,120	4,352	578	662	724	750	778	1,315	1,881	2,165
Circuit 168	3,546	963	1,226	1,404	1,535	1,592	1,649	2,789	3,990	4,591
Circuit 169	4,029	2,935	3,628	4,156	4,544	4,710	4,882	5,088	5,088	5,088
Circuit 170	1,120	952	409	469	513	532	551	932	1,333	1,533
Circuit 171	4,969	3,827	248	284	311	322	334	565	808	930
Circuit 172	2,755	2,342	362	414	453	469	487	823	1,177	1,354
Circuit 173	624	531	442	506	554	574	595	1,006	1,439	1,469
Circuit 174	3,230	2,745	928	1,063	1,162	1,205	1,248	2,111	3,001	3,001
Circuit 175	7,927	5,784	692	792	866	898	930	1,573	2,251	2,590
Circuit 176	721	613	–	–	–	–	–	–	–	–
Circuit 177	4,497	3,822	1,617	1,852	2,025	2,099	2,175	3,679	4,211	4,211
Circuit 178	7,024	6,024	1,275	1,460	1,596	1,655	1,715	2,900	3,764	3,764
Circuit 179	3,851	3,052	115	131	144	149	154	261	373	429
Circuit 180	5,782	4,088	83	95	104	108	111	188	270	310
Circuit 181	83	62	–	–	–	–	–	–	–	–
Circuit 182	3,416	2,510	116	133	145	150	156	263	377	433
Circuit 183	11,185	9,507	500	573	626	649	673	1,138	1,627	1,872
Circuit 184	5,907	5,021	270	309	338	351	363	614	879	1,011
Circuit 185	6,299	5,354	1,945	2,228	2,436	2,525	2,617	4,425	5,022	5,022
Circuit 186	1,088	707	957	1,097	1,199	1,243	1,288	2,178	3,116	3,534
Circuit 187	3,487	2,964	355	407	445	461	478	808	1,156	1,330

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 188	6,420	5,641	282	323	354	367	380	642	919	1,057
Circuit 189	60	52	–	–	–	–	–	–	–	–
Circuit 190	4,546	3,864	–	–	–	–	–	–	–	–
Circuit 191	3,108	2,642	2,350	2,692	2,944	3,052	3,162	5,347	5,473	5,473
Circuit 192	1,030	450	635	727	795	824	854	1,444	2,065	2,376
Circuit 193	3,249	759	–	–	–	–	–	–	–	–
Circuit 194	4,897	4,163	1,897	2,173	2,376	2,462	2,552	4,315	4,339	4,339
Circuit 195	4,138	3,518	1,373	1,573	1,720	1,783	1,848	2,547	2,547	2,547
Circuit 196	7,671	6,520	2,649	3,034	3,318	3,439	3,564	6,026	8,157	8,157
Circuit 197	10,634	9,039	4,440	5,087	5,562	5,765	5,975	9,517	9,517	9,517
Circuit 198	952	809	203	232	254	263	268	268	268	268
Circuit 199	4,410	3,749	1,676	1,920	2,099	2,176	2,255	3,813	4,618	4,618
Circuit 200	4,112	1,608	1,137	1,303	1,425	1,477	1,530	2,588	3,400	3,400
Circuit 201	4,019	3,416	2,551	2,922	3,195	3,312	3,432	5,804	6,161	6,161
Circuit 202	4,355	2,666	1,694	1,941	2,122	2,199	2,279	3,854	3,897	3,897
Circuit 203	505	430	87	100	109	113	117	144	144	144
Circuit 204	5,370	4,565	39	44	48	50	52	88	126	144
Circuit 205	983	835	–	–	–	–	–	–	–	–
Circuit 206	3,562	3,027	–	–	–	–	–	–	–	–
Circuit 207	4,274	3,083	58	66	72	75	78	131	188	216
Circuit 208	3,627	1,295	836	957	1,046	1,085	1,124	1,901	2,720	3,129
Circuit 209	1,711	1,454	545	624	683	708	733	1,240	1,774	2,041
Circuit 210	3,125	2,693	1,537	1,761	1,925	1,995	2,068	3,497	5,003	5,078
Circuit 211	6,616	5,808	3,213	3,680	4,024	4,171	4,323	7,310	9,474	9,474
Circuit 212	5,706	5,033	2,562	2,935	3,209	3,327	3,448	5,830	7,214	7,214
Circuit 213	1,903	1,471	1,139	1,304	1,426	1,478	1,532	2,591	3,706	4,113
Circuit 214	8,176	6,950	350	401	438	454	471	796	1,139	1,311
Circuit 215	5,354	3,717	1,590	1,821	1,992	2,064	2,139	3,618	4,244	4,244
Circuit 216	2,008	1,706	609	697	762	790	819	1,385	1,464	1,464
Circuit 217	5,447	4,630	1,120	1,283	1,403	1,454	1,464	1,464	1,464	1,464
Circuit 218	3,541	3,010	1,371	1,570	1,717	1,780	1,845	3,119	4,462	4,877
Circuit 219	179	152	–	–	–	–	–	–	–	–
Circuit 220	2,869	2,438	1,993	2,283	2,497	2,588	2,682	4,535	6,316	6,316
Circuit 221	6,009	4,641	1,722	1,973	2,157	2,236	2,317	3,918	5,606	5,659
Circuit 222	2,079	1,767	1,602	1,835	2,006	2,080	2,155	3,645	4,802	4,802
Circuit 223	5,005	2,998	907	1,039	1,136	1,177	1,220	2,063	2,952	3,163
Circuit 224	2,919	2,127	350	401	438	454	471	796	1,029	1,029
Circuit 225	8,145	6,776	863	989	1,081	1,121	1,162	1,964	2,810	3,233

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 226	1,186	578	322	369	404	419	434	734	1,050	1,207
Circuit 227	190	162	35	40	43	45	47	79	88	88
Circuit 228	2,419	676	917	1,050	1,148	1,190	1,233	2,086	2,984	3,433
Circuit 229	7,351	6,249	2,573	2,948	3,223	3,341	3,462	5,854	6,995	6,995
Circuit 230	4,579	3,892	1,027	1,177	1,287	1,334	1,382	2,337	3,344	3,847
Circuit 231	2,090	1,777	599	686	751	778	806	1,363	1,951	2,244
Circuit 232	4,899	4,237	96	110	120	125	129	218	312	360
Circuit 233	7,858	4,263	2,930	3,356	3,669	3,804	3,942	6,665	8,207	8,207
Circuit 234	1,663	1,532	294	337	369	382	396	669	679	679
Circuit 235	5,011	4,027	2,338	2,679	2,929	3,036	3,146	4,380	4,380	4,380
Circuit 236	8,704	4,964	3,984	4,564	4,990	5,172	5,360	8,657	8,657	8,657
Circuit 237	4,312	4,027	2,592	2,969	3,246	3,365	3,487	5,896	7,079	7,079
Circuit 238	748	717	958	1,097	1,199	1,243	1,288	2,179	2,328	2,328
Circuit 239	3,566	3,031	1,897	2,173	2,376	2,463	2,553	4,316	6,175	7,061
Circuit 240	4,602	4,036	2	3	3	3	3	6	8	9
Circuit 241	8,243	6,839	2,600	2,978	3,256	3,376	3,498	3,515	3,515	3,515
Circuit 242	1,597	1,256	365	418	457	474	491	830	1,188	1,366
Circuit 243	177	2,344	–	–	–	–	–	–	–	–
Circuit 244	2,979	3,794	679	777	850	881	913	1,544	2,209	2,541
Circuit 245	5,261	3,543	2,168	2,484	2,716	2,815	2,917	4,933	5,756	5,756
Circuit 246	711	226	–	–	–	–	–	–	–	–
Circuit 247	4,259	3,857	438	502	548	568	589	996	1,425	1,640
Circuit 248	4,452	793	1,099	1,259	1,376	1,426	1,478	2,500	3,410	3,410
Circuit 249	3,632	432	228	261	286	296	307	519	743	855
Circuit 250	2,345	1,993	1,140	1,306	1,428	1,480	1,534	2,593	3,630	3,630
Circuit 251	8,975	5,107	8,105	9,284	10,152	10,413	10,413	10,413	10,413	10,413
Circuit 252	2,897	963	1,507	1,726	1,887	1,956	2,027	3,428	4,128	4,128
Circuit 253	108	92	–	–	–	–	–	–	–	–
Circuit 254	7,195	6,288	585	670	733	759	787	1,331	1,776	1,776
Circuit 255	5,548	5,328	536	614	672	696	722	1,220	1,740	1,740
Circuit 256	3,836	3,624	726	832	910	943	977	1,653	1,989	1,989
Circuit 257	5,354	5,059	1,474	1,688	1,846	1,914	1,983	3,353	4,798	5,520
Circuit 258	5,212	2,335	4,705	5,390	5,893	6,109	6,331	8,958	8,958	8,958
Circuit 259	3,216	2,781	6,168	6,253	6,253	6,253	6,253	6,253	6,253	6,253
Circuit 260	8,148	5,689	4,628	5,301	5,796	6,009	6,227	10,529	13,715	13,715
Circuit 261	4,605	3,914	2,195	2,515	2,750	2,850	2,954	4,995	6,101	6,101
Circuit 262	5,475	4,654	1,483	1,699	1,858	1,926	1,996	3,375	4,276	4,276
Circuit 263	3,763	3,199	2,552	2,923	3,196	3,271	3,271	3,271	3,271	3,271

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 264	5,762	4,898	4,075	4,668	5,104	5,291	5,483	5,637	5,637	5,637
Circuit 265	5,107	3,907	762	873	954	989	1,025	1,733	1,925	1,925
Circuit 266	3,937	3,346	182	208	228	236	245	414	592	681
Circuit 267	2,933	2,493	471	540	590	612	634	650	650	650
Circuit 268	6,033	5,128	1,623	1,859	2,033	2,107	2,184	3,692	5,283	5,706
Circuit 269	4,641	3,945	–	–	–	–	–	–	–	–
Circuit 270	4,421	3,758	1,116	1,278	1,398	1,449	1,501	2,539	3,098	3,098
Circuit 271	4,171	3,545	2,511	2,876	3,144	3,260	3,378	5,712	6,041	6,041
Circuit 272	1,154	981	495	567	620	643	666	1,126	1,611	1,853
Circuit 273	2,143	1,822	457	524	573	594	615	1,041	1,489	1,713
Circuit 274	2,946	2,504	1,520	1,742	1,904	1,974	2,046	3,459	4,389	4,389
Circuit 275	7,570	5,984	3,619	4,146	4,533	4,699	4,870	6,395	6,395	6,395
Circuit 276	3,122	3,475	4,129	4,129	4,129	4,129	4,129	4,129	4,129	4,129
Circuit 277	4,614	4,103	2,334	2,674	2,924	3,031	3,141	5,311	6,926	6,926
Circuit 278	4,340	3,953	2,186	2,504	2,738	2,838	2,941	4,974	6,154	6,154
Circuit 279	1,177	1,057	986	1,129	1,235	1,280	1,326	1,798	1,798	1,798
Circuit 280	2,936	2,495	897	1,027	1,123	1,164	1,206	2,040	2,919	3,358
Circuit 281	1,316	772	1,169	1,339	1,464	1,518	1,573	2,660	3,496	3,496
Circuit 282	4,214	780	1,137	1,302	1,424	1,476	1,530	2,587	3,701	4,258
Circuit 283	3,839	2,871	1,028	1,177	1,287	1,335	1,383	2,339	3,346	3,849
Circuit 284	2,299	1,954	1,798	2,059	2,251	2,334	2,419	4,090	4,985	4,985
Circuit 285	5,662	1,636	2,961	3,392	3,709	3,845	3,984	6,737	7,920	7,920
Circuit 286	5,271	4,480	33	38	42	43	45	76	109	125
Circuit 287	3,252	2,048	1,978	2,266	2,478	2,568	2,662	4,501	4,863	4,863
Circuit 288	9,600	3,270	3,026	3,466	3,790	3,928	4,071	6,802	6,802	6,802
Circuit 289	2,667	3,617	265	304	332	344	357	603	862	992
Circuit 290	2,772	1,028	1,170	1,340	1,464	1,464	1,464	1,464	1,464	1,464
Circuit 291	4,820	3,749	968	1,109	1,213	1,257	1,303	2,203	3,152	3,627
Circuit 292	5,222	2,086	970	1,112	1,215	1,260	1,306	2,208	3,111	3,111
Circuit 293	5,768	4,903	1,383	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Circuit 294	6,307	3,281	767	878	960	996	1,032	1,745	2,496	2,871
Circuit 295	4,017	3,617	328	376	411	426	442	747	903	903
Circuit 296	4,136	2,357	412	472	516	535	555	938	1,342	1,361
Circuit 297	3,545	1,694	1,575	1,804	1,973	2,045	2,119	3,583	4,239	4,239
Circuit 298	4,054	3,446	2,444	2,800	3,062	3,174	3,289	5,561	5,972	5,972
Circuit 299	6,304	3,496	844	967	1,057	1,096	1,136	1,921	2,748	3,162
Circuit 300	4,455	1,469	1,791	2,052	2,243	2,325	2,410	4,075	5,830	6,707
Circuit 301	1,053	496	484	554	606	628	651	1,100	1,574	1,811

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 302	4,019	3,416	1,763	2,019	2,208	2,288	2,372	4,010	5,737	5,758
Circuit 303	6,695	3,596	4,674	5,354	5,854	6,068	6,289	10,430	10,430	10,430
Circuit 304	2,526	2,147	1,365	1,564	1,710	1,772	1,837	2,893	2,893	2,893
Circuit 305	1,852	740	964	1,105	1,208	1,252	1,298	2,194	3,139	3,611
Circuit 306	2,635	1,809	68	78	85	88	91	155	221	254
Circuit 307	4,943	4,202	2,091	2,395	2,619	2,715	2,813	4,757	5,801	5,801
Circuit 308	1,236	1,051	1,080	1,237	1,352	1,402	1,453	2,457	3,039	3,039
Circuit 309	1,140	714	469	537	587	609	631	1,067	1,527	1,757
Circuit 310	6,808	5,787	465	532	582	603	625	1,057	1,512	1,740
Circuit 311	6,285	5,342	460	527	576	597	619	1,047	1,497	1,723
Circuit 312	3,034	2,579	–	–	–	–	–	–	–	–
Circuit 313	3,923	2,934	1,799	2,061	2,254	2,336	2,421	4,094	4,949	4,949
Circuit 314	5,183	4,405	1,612	1,846	2,019	2,093	2,169	3,667	3,805	3,805
Circuit 315	3,086	2,623	489	560	612	635	658	1,112	1,591	1,831
Circuit 316	1,536	1,305	265	304	332	344	357	603	731	731
Circuit 317	5,006	3,868	48	55	60	62	65	109	157	180
Circuit 318	5,261	3,540	216	247	271	280	291	491	703	809
Circuit 319	4,865	4,135	349	400	438	454	470	795	1,137	1,308
Circuit 320	5,762	2,253	2,266	2,596	2,838	2,942	3,049	5,155	5,474	5,474
Circuit 321	337	287	79	90	99	102	106	179	256	295
Circuit 322	4,669	4,724	747	856	936	970	1,005	1,620	1,620	1,620
Circuit 323	144	123	–	–	–	–	–	–	–	–
Circuit 324	5,894	5,010	2,371	2,716	2,970	3,079	3,190	3,581	3,581	3,581
Circuit 325	608	588	501	574	628	651	675	1,141	1,632	1,878
Circuit 326	1,410	762	858	983	1,074	1,114	1,154	1,952	2,792	3,212
Circuit 327	1,463	511	1,311	1,502	1,511	1,511	1,511	1,511	1,511	1,511
Circuit 328	6,119	5,201	3,099	3,550	3,882	4,024	4,170	7,051	7,283	7,283
Circuit 329	1,610	1,369	1,053	1,206	1,318	1,367	1,416	2,395	3,426	3,519
Circuit 330	5,881	4,999	3,528	4,041	4,419	4,580	4,747	6,592	6,592	6,592
Circuit 331	924	785	95	108	119	123	127	215	308	355
Circuit 332	7,351	3,171	3,679	4,215	4,608	4,777	4,951	8,371	10,701	10,701
Circuit 333	5,964	5,069	1,020	1,168	1,277	1,324	1,372	2,320	3,319	3,818
Circuit 334	2,507	2,131	479	549	600	622	645	1,090	1,560	1,795
Circuit 335	3,598	3,058	1,369	1,568	1,714	1,777	1,842	2,649	2,649	2,649
Circuit 336	5,827	4,953	2,046	2,344	2,563	2,657	2,753	4,210	4,210	4,210
Circuit 337	3,697	3,143	1,061	1,216	1,329	1,378	1,428	2,415	3,455	3,975
Circuit 338	959	815	204	233	255	264	274	463	663	762
Circuit 339	9,020	7,667	2,362	2,705	2,958	3,066	3,178	4,111	4,111	4,111

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 340	3,646	3,099	1,452	1,663	1,818	1,885	1,953	3,303	4,675	4,675
Circuit 341	746	634	–	–	–	–	–	–	–	–
Circuit 342	4,140	1,454	1,864	2,136	2,335	2,421	2,509	4,242	6,069	6,982
Circuit 343	5,806	4,935	2,484	2,845	3,111	3,225	3,342	5,651	5,760	5,760
Circuit 344	4,257	3,619	1,738	1,991	2,177	2,257	2,339	3,468	3,468	3,468
Circuit 345	9,447	6,464	738	845	924	958	993	1,679	2,402	2,764
Circuit 346	4,257	3,619	1,580	1,810	1,979	2,052	2,126	3,596	4,565	4,565
Circuit 347	6,038	3,233	2,664	3,052	3,337	3,459	3,584	6,061	7,164	7,164
Circuit 348	3,111	1,014	1,179	1,351	1,477	1,531	1,587	2,683	3,838	4,416
Circuit 349	419	356	473	542	592	614	636	1,076	1,539	1,770
Circuit 350	6,149	3,240	2,547	2,918	3,191	3,307	3,428	5,796	7,505	7,505
Circuit 351	3,133	2,663	–	–	–	–	–	–	–	–
Circuit 352	2,391	1,567	44	44	44	44	44	44	44	44
Circuit 353	7,969	5,222	–	–	–	–	–	–	–	–
Circuit 354	6,602	5,612	24	27	30	31	32	55	78	90
Circuit 355	6,104	5,188	121	139	152	157	163	276	395	454
Circuit 356	3,888	3,304	46	53	58	60	62	105	150	172
Circuit 357	4,256	3,618	–	–	–	–	–	–	–	–
Circuit 358	2,982	2,535	1,070	1,226	1,340	1,389	1,440	2,435	3,483	3,940
Circuit 359	6,054	949	3,858	4,420	4,833	5,009	5,191	8,778	11,248	11,248
Circuit 360	1,341	513	595	682	746	773	801	1,355	1,464	1,464
Circuit 361	277	122	151	173	189	196	203	343	491	565
Circuit 362	6,306	5,364	1,308	1,499	1,639	1,699	1,761	2,977	4,259	4,433
Circuit 363	4,376	3,725	1,679	1,923	2,103	2,180	2,259	3,517	3,517	3,517
Circuit 364	5,368	4,562	3,881	4,445	4,861	5,038	5,221	7,650	7,650	7,650
Circuit 365	4,712	2,283	1,561	1,788	1,956	2,027	2,101	3,552	5,003	5,003
Circuit 366	4,162	1,910	1,120	1,283	1,403	1,455	1,507	2,549	3,647	4,196
Circuit 367	2,068	1,758	1,173	1,343	1,469	1,523	1,578	2,668	3,817	4,392
Circuit 368	4,623	1,336	1,540	1,764	1,929	1,999	2,072	3,503	5,012	5,766
Circuit 369	5,678	4,380	2,925	3,350	3,663	3,797	3,935	6,654	9,264	9,264
Circuit 370	3,020	524	526	603	659	683	708	1,198	1,713	1,971
Circuit 371	4,080	913	2,136	2,447	2,675	2,773	2,874	4,859	6,938	6,938
Circuit 372	5,743	4,882	3,688	4,225	4,620	4,789	4,962	8,391	8,592	8,592
Circuit 373	7,141	5,038	4,995	5,722	6,256	6,485	6,721	9,886	9,886	9,886
Circuit 374	4,249	3,612	1,302	1,491	1,630	1,690	1,751	2,961	3,670	3,670
Circuit 375	4,040	3,434	754	864	945	979	1,015	1,716	2,455	2,824
Circuit 376	1,431	1,216	847	971	1,061	1,100	1,140	1,928	2,223	2,223
Circuit 377	1,821	717	1,084	1,241	1,357	1,407	1,458	2,465	3,527	3,686

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 378	308	262	37	42	46	47	49	83	119	137
Circuit 379	3,073	2,069	1,454	1,665	1,821	1,887	1,956	3,307	4,732	5,216
Circuit 380	1,552	1,319	1,666	1,908	2,086	2,163	2,241	3,789	4,163	4,163
Circuit 381	1,106	640	907	1,039	1,136	1,178	1,221	2,064	2,953	3,398
Circuit 382	–	–	24,363	40,100	81,458	122,815	164,173	381,960	381,960	381,960

Table N-6. Hawaiian Electric Distribution Circuit High DG-PV Forecast (kW)

Maui Electric Distribution Circuit Base DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	3,302	2,871	2,476	2,845	2,845	2,845	2,845	2,845	2,845	2,845
Circuit 2	1,233	1,072	852	873	873	873	873	873	873	873
Circuit 3	166	145	170	170	170	170	170	170	170	170
Circuit 4	22	19	32	32	32	32	32	32	32	32
Circuit 5	29	26	48	56	57	57	58	60	63	65
Circuit 6	188	163	215	215	215	215	215	215	215	215
Circuit 7	3,192	2,776	948	1,018	1,018	1,018	1,018	1,018	1,018	1,018
Circuit 8	3,602	3,132	3,063	3,536	3,592	3,592	3,592	3,592	3,592	3,592
Circuit 9	473	411	1,118	1,291	1,312	1,326	1,339	1,383	1,452	1,452
Circuit 10	330	287	998	1,033	1,033	1,033	1,033	1,033	1,033	1,033
Circuit 11	283	246	436	486	486	486	486	486	486	486
Circuit 12	77	67	9	9	9	9	9	9	9	9
Circuit 13	–	–	166	166	166	166	166	166	166	166
Circuit 14	5,807	5,049	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452
Circuit 15	2,141	1,862	823	823	823	823	823	823	823	823
Circuit 16	5,115	4,448	2,065	2,384	2,423	2,449	2,472	2,554	2,698	2,698
Circuit 17	4,569	3,973	2,163	2,497	2,537	2,565	2,589	2,675	2,835	2,891
Circuit 18	6,033	5,246	1,447	1,670	1,697	1,715	1,732	1,789	1,896	1,985
Circuit 19	8,174	7,108	7,963	7,963	7,963	7,963	7,963	7,963	7,963	7,963
Circuit 20	1,117	971	850	895	895	895	895	895	895	895
Circuit 21	199	173	31	35	36	36	37	38	40	42
Circuit 22	5,168	4,494	2,111	2,111	2,111	2,111	2,111	2,111	2,111	2,111
Circuit 23	5,963	5,185	3,213	3,680	3,680	3,680	3,680	3,680	3,680	3,680
Circuit 24	1,133	985	3,885	4,485	4,557	4,607	4,650	4,805	4,929	4,929
Circuit 25	1,806	1,570	4,492	5,186	5,269	5,327	5,377	5,556	5,559	5,559
Circuit 26	629	547	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Circuit 27	7,439	6,469	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
Circuit 28	539	469	571	659	670	677	684	690	690	690
Circuit 29	2,599	2,260	3,115	3,596	3,654	3,694	3,728	3,829	3,829	3,829
Circuit 30	2,103	1,829	2,901	3,350	3,398	3,398	3,398	3,398	3,398	3,398
Circuit 31	153	133	553	608	608	608	608	608	608	608
Circuit 32	6,784	5,899	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717
Circuit 33	3,009	2,616	2,734	3,157	3,207	3,242	3,273	3,382	3,477	3,477
Circuit 34	2,091	1,818	589	680	691	697	697	697	697	697
Circuit 35	2,003	1,742	189	219	222	225	227	234	248	260
Circuit 36	2,361	2,053	3,066	3,445	3,445	3,445	3,445	3,445	3,445	3,445

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	1,728	1,502	245	245	245	245	245	245	245	245
Circuit 38	950	826	4,619	5,333	5,342	5,342	5,342	5,342	5,342	5,342
Circuit 39	4,118	3,580	4,086	4,718	4,761	4,761	4,761	4,761	4,761	4,761
Circuit 40	2,366	2,057	570	659	669	676	683	705	748	783
Circuit 41	12,197	10,606	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083
Circuit 42	1,255	1,091	331	382	388	392	396	409	434	454
Circuit 43	4,481	3,897	2,853	2,853	2,853	2,853	2,853	2,853	2,853	2,853
Circuit 44	1,354	1,178	1,030	1,190	1,206	1,206	1,206	1,206	1,206	1,206
Circuit 45	1,502	1,306	1,415	1,634	1,660	1,678	1,694	1,732	1,732	1,732
Circuit 46	1,286	1,119	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
Circuit 47	–	–	–	–	–	–	–	–	–	–
Circuit 48	1,470	1,278	670	670	670	670	670	670	670	670
Circuit 49	–	–	22	26	26	26	26	27	29	30
Circuit 50	–	–	–	–	–	–	–	–	–	–
Circuit 51	4,885	4,248	501	579	588	595	600	600	600	600
Circuit 52	2,255	1,961	3,066	3,278	3,278	3,278	3,278	3,278	3,278	3,278
Circuit 53	1,557	1,354	995	995	995	995	995	995	995	995
Circuit 54	–	–	227	227	227	227	227	227	227	227
Circuit 55	850	740	1,304	1,418	1,418	1,418	1,418	1,418	1,418	1,418
Circuit 56	319	277	476	549	558	564	569	588	589	589
Circuit 57	510	443	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465
Circuit 58	1,424	1,238	1,892	1,912	1,912	1,912	1,912	1,912	1,912	1,912
Circuit 59	2,861	2,488	3,105	3,585	3,642	3,682	3,716	3,840	3,890	3,890
Circuit 60	1,036	901	7	8	8	8	8	9	9	10
Circuit 61	5,040	4,383	4,584	5,028	5,028	5,028	5,028	5,028	5,028	5,028
Circuit 62	1,285	1,118	395	456	463	468	473	488	518	542
Circuit 63	13,815	12,013	1,980	2,286	2,322	2,348	2,370	2,449	2,534	2,534
Circuit 64	4,346	3,779	466	466	466	466	466	466	466	466
Circuit 65	5,733	4,986	2,636	2,706	2,706	2,706	2,706	2,706	2,706	2,706
Circuit 66	714	621	34	34	34	34	34	34	34	34
Circuit 67	738	642	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
Circuit 68	1,792	1,558	2,328	2,688	2,731	2,760	2,786	2,871	2,871	2,871
Circuit 69	3,834	3,334	3,544	3,862	3,862	3,862	3,862	3,862	3,862	3,862
Circuit 70	3,736	3,249	1,137	1,195	1,195	1,195	1,195	1,195	1,195	1,195
Circuit 71	1,720	1,496	430	496	504	510	515	532	564	583
Circuit 72	3,406	2,962	899	1,037	1,054	1,066	1,076	1,111	1,178	1,183
Circuit 73	7,841	6,818	7,736	8,933	9,076	9,174	9,261	9,521	9,521	9,521
Circuit 74	830	722	257	297	301	305	308	311	311	311

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	951	827	100	100	100	100	100	100	100	100
Circuit 76	4,062	3,532	2,348	2,706	2,706	2,706	2,706	2,706	2,706	2,706
Circuit 77	2,991	2,601	613	708	719	727	734	758	803	814
Circuit 78	5,882	5,115	1,443	1,666	1,693	1,694	1,694	1,694	1,694	1,694
Circuit 79	3,908	3,398	1,066	1,066	1,066	1,066	1,066	1,066	1,066	1,066
Circuit 80	3,928	3,416	438	504	504	504	504	504	504	504
Circuit 81	3,494	3,038	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Circuit 82	2,645	2,300	2,754	2,974	2,974	2,974	2,974	2,974	2,974	2,974
Circuit 83	1,596	1,388	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315
Circuit 84	3,169	2,756	2,207	2,548	2,589	2,617	2,642	2,730	2,894	2,913
Circuit 85	–	–	–	–	–	–	–	–	–	–
Circuit 86	5,449	4,738	2,896	3,344	3,398	3,435	3,467	3,488	3,488	3,488
Circuit 87	1,055	917	585	585	585	585	585	585	585	585
Circuit 88	560	487	909	909	909	909	909	909	909	909
Circuit 89	625	543	837	846	846	846	846	846	846	846
Circuit 90	418	364	597	611	611	611	611	611	611	611
Circuit 91	75	65	95	109	111	112	113	117	124	130
Circuit 92	1,002	872	1,214	1,402	1,425	1,440	1,454	1,462	1,462	1,462
Circuit 93	122	106	159	159	159	159	159	159	159	159
Circuit 94	207	180	316	364	370	374	378	390	414	433
Circuit 95	804	700	1,448	1,549	1,549	1,549	1,549	1,549	1,549	1,549
Circuit 96	276	240	299	299	299	299	299	299	299	299
Circuit 97	599	521	332	348	348	348	348	348	348	348
Circuit 98	1,037	902	56	56	56	56	56	56	56	56
Circuit 99	520	452	12	14	14	14	14	15	15	16
Circuit 100	377	328	382	382	382	382	382	382	382	382
Circuit 101	2106	1831	2,625	3,031	3,079	3,113	3,142	3,247	3,441	3,602
Circuit 102	2604	2265	644	661	661	661	661	661	661	661

Table N-7. Maui Electric Distribution Circuit Base DG-PV Forecast (kW)

Maui Electric Distribution Circuit High DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	3,302	2,871	2,661	3,114	3,269	3,367	3,435	6,436	7,697	7,697
Circuit 2	1,233	1,072	916	1,072	1,125	1,159	1,182	2,215	3,342	3,874
Circuit 3	166	145	225	263	276	285	290	544	599	599
Circuit 4	22	19	43	50	53	54	55	104	138	138
Circuit 5	29	26	52	61	64	66	67	125	189	219
Circuit 6	188	163	284	332	349	359	366	686	1,035	1,200
Circuit 7	3,192	2,776	1,019	1,094	1,094	1,094	1,094	1,094	1,094	1,094
Circuit 8	3,602	3,132	3,292	3,851	4,044	4,165	4,248	7,077	7,077	7,077
Circuit 9	473	411	1,202	1,406	1,476	1,521	1,551	2,906	4,385	5,083
Circuit 10	330	287	1,073	1,255	1,318	1,358	1,385	2,595	3,915	4,539
Circuit 11	283	246	469	549	576	593	605	1,134	1,711	1,984
Circuit 12	77	67	12	14	15	15	15	29	43	44
Circuit 13	–	–	219	256	269	277	283	530	800	927
Circuit 14	5,807	5,049	1,917	2,242	2,355	2,425	2,474	4,635	6,240	6,240
Circuit 15	2,141	1,862	1,087	1,271	1,335	1,375	1,402	2,628	3,965	4,597
Circuit 16	5,115	4,448	2,219	2,597	2,726	2,808	2,864	5,367	6,252	6,252
Circuit 17	4,569	3,973	2,324	2,719	2,855	2,941	3,000	5,621	6,816	6,816
Circuit 18	6,033	5,246	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Circuit 19	8,174	7,108	9,043	9,462	9,462	9,462	9,462	9,462	9,462	9,462
Circuit 20	1,117	971	914	1,069	1,122	1,156	1,179	2,210	3,334	3,865
Circuit 21	199	173	33	38	40	42	42	79	120	139
Circuit 22	5,168	4,494	2,521	2,950	3,097	3,190	3,254	6,097	6,398	6,398
Circuit 23	5,963	5,185	3,453	4,040	4,242	4,369	4,457	7,346	7,346	7,346
Circuit 24	1,133	985	4,175	4,885	5,129	5,283	5,388	5,992	5,992	5,992
Circuit 25	1,806	1,570	4,827	5,648	5,930	6,108	6,230	8,241	8,241	8,241
Circuit 26	629	547	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Circuit 27	7,439	6,469	7,708	7,708	7,708	7,708	7,708	7,708	7,708	7,708
Circuit 28	539	469	614	718	754	777	792	1,485	2,240	2,597
Circuit 29	2,599	2,260	3,347	3,916	4,112	4,236	4,320	8,096	8,236	8,236
Circuit 30	2,103	1,829	3,118	3,648	3,830	3,945	4,024	7,540	8,085	8,085
Circuit 31	153	133	594	696	730	752	767	1,438	2,169	2,515
Circuit 32	6,784	5,899	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717
Circuit 33	3,009	2,616	2,938	3,438	3,610	3,718	3,792	6,752	6,752	6,752
Circuit 34	2,091	1,818	633	741	778	801	817	1,531	2,310	2,678
Circuit 35	2,003	1,742	203	238	250	257	263	366	366	366
Circuit 36	2,361	2,053	3,295	3,855	4,048	4,169	4,253	6,854	6,854	6,854

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	1,728	1,502	279	327	343	353	361	535	535	535
Circuit 38	950	826	4,964	5,808	6,098	6,281	6,407	8,395	8,395	8,395
Circuit 39	4,118	3,580	4,391	5,138	5,395	5,557	5,668	7,838	7,838	7,838
Circuit 40	2,366	2,057	464	464	464	464	464	464	464	464
Circuit 41	12,197	10,606	2,598	2,598	2,598	2,598	2,598	2,598	2,598	2,598
Circuit 42	1,255	1,091	355	416	437	450	459	860	1,297	1,504
Circuit 43	4,481	3,897	3,704	4,333	4,550	4,686	4,780	6,631	6,631	6,631
Circuit 44	1,354	1,178	1,107	1,296	1,360	1,401	1,429	2,678	4,040	4,684
Circuit 45	1,502	1,306	1,520	1,779	1,868	1,924	1,962	3,677	5,548	6,432
Circuit 46	1,286	1,119	1,330	1,556	1,633	1,682	1,716	3,216	4,852	5,625
Circuit 47	–	–	–	–	–	–	–	–	–	–
Circuit 48	1,470	1,278	884	1,034	1,086	1,118	1,141	2,138	3,225	3,739
Circuit 49	–	–	24	28	29	30	31	57	87	101
Circuit 50	–	–	–	–	–	–	–	–	–	–
Circuit 51	4,885	4,248	539	630	662	682	696	1,043	1,043	1,043
Circuit 52	2,255	1,961	3,295	3,855	4,048	4,169	4,253	5,720	5,720	5,720
Circuit 53	1,557	1,354	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Circuit 54	–	–	299	350	368	379	386	724	1,092	1,266
Circuit 55	850	740	1,402	1,640	1,722	1,774	1,809	3,390	5,115	5,930
Circuit 56	319	277	511	598	628	647	660	1,236	1,865	2,162
Circuit 57	510	443	1,712	2,003	2,103	2,166	2,209	4,140	6,246	6,624
Circuit 58	1,424	1,238	2,033	2,379	2,498	2,573	2,624	4,918	6,504	6,504
Circuit 59	2,861	2,488	3,337	3,904	4,099	4,222	4,306	8,070	8,628	8,628
Circuit 60	1,036	901	7	9	9	9	10	18	27	31
Circuit 61	5,040	4,383	4,927	5,764	6,052	6,234	6,359	8,835	8,835	8,835
Circuit 62	1,285	1,118	424	496	521	537	548	1,026	1,548	1,795
Circuit 63	13,815	12,013	2,128	2,489	2,614	2,692	2,746	3,617	3,617	3,617
Circuit 64	4,346	3,779	616	720	756	779	795	1,236	1,236	1,236
Circuit 65	5,733	4,986	2,833	3,315	3,481	3,585	3,657	6,852	7,565	7,565
Circuit 66	714	621	45	52	55	57	58	108	163	164
Circuit 67	738	642	1,275	1,492	1,566	1,613	1,646	3,084	4,653	5,394
Circuit 68	1,792	1,558	2,502	2,927	3,073	3,165	3,229	6,050	6,810	6,810
Circuit 69	3,834	3,334	3,808	4,456	4,679	4,819	4,915	7,941	7,941	7,941
Circuit 70	3,736	3,249	1,222	1,429	1,501	1,546	1,577	2,955	4,458	5,168
Circuit 71	1,720	1,496	462	540	567	584	596	1,117	1,686	1,954
Circuit 72	3,406	2,962	966	1,130	1,186	1,222	1,246	2,336	3,524	4,085
Circuit 73	7,841	6,818	8,314	9,190	9,190	9,190	9,190	9,190	9,190	9,190
Circuit 74	830	722	276	323	339	349	356	668	1,008	1,168

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	951	827	132	154	162	167	170	319	481	557
Circuit 76	4,062	3,532	2,523	2,952	3,100	3,193	3,257	6,103	6,758	6,758
Circuit 77	2,991	2,601	659	735	735	735	735	735	735	735
Circuit 78	5,882	5,115	1,551	1,815	1,834	1,834	1,834	1,834	1,834	1,834
Circuit 79	3,908	3,398	1,407	1,646	1,729	1,780	1,816	3,403	5,134	5,946
Circuit 80	3,928	3,416	471	551	578	596	608	1,139	1,241	1,241
Circuit 81	3,494	3,038	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Circuit 82	2,645	2,300	2,960	3,463	3,636	3,745	3,820	7,036	7,036	7,036
Circuit 83	1,596	1,388	1,735	2,030	2,132	2,196	2,240	4,197	6,332	6,769
Circuit 84	3,169	2,756	2,372	2,775	2,914	3,001	3,061	5,736	6,224	6,224
Circuit 85	–	–	–	–	–	–	–	–	–	–
Circuit 86	5,449	4,738	3,112	3,642	3,824	3,938	4,017	6,833	6,833	6,833
Circuit 87	1,055	917	717	838	880	907	925	1,733	2,615	3,031
Circuit 88	560	487	1,056	1,235	1,297	1,336	1,362	2,553	3,852	4,465
Circuit 89	625	543	900	1,052	1,105	1,138	1,161	2,176	3,282	3,805
Circuit 90	418	364	642	751	788	812	828	1,552	2,341	2,714
Circuit 91	75	65	102	119	125	129	131	246	249	249
Circuit 92	1,002	872	1,305	1,527	1,603	1,651	1,684	1,688	1,688	1,688
Circuit 93	122	106	191	208	212	218	225	366	512	593
Circuit 94	207	180	319	347	354	365	376	612	855	991
Circuit 95	804	700	1,462	1,594	1,626	1,675	1,725	1,728	1,728	1,728
Circuit 96	276	240	346	378	385	397	409	665	930	959
Circuit 97	599	521	335	365	372	383	395	500	500	500
Circuit 98	1,037	902	57	62	63	65	67	109	152	176
Circuit 99	520	452	12	13	13	14	14	23	32	37
Circuit 100	377	328	474	541	573	619	663	2,227	2,759	2,759
Circuit 101	2,106	1,831	2,188	2,188	2,188	2,188	2,188	2,188	2,188	2,188
Circuit 102	2,604	2,265	661	753	799	862	923	2,753	2,753	2,753

Table N-8. Maui Electric Distribution Circuit High DG-PV Forecast (kW)

Hawai'i Electric Light Distribution Circuit Base DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,279	5,337	1,334	1,549	1,612	1,659	1,706	1,996	2,370	2,701
Circuit 2	1,552	1,319	340	395	411	423	435	509	604	689
Circuit 3	1,952	1,659	–	–	–	–	–	–	–	–
Circuit 4	2,529	2,150	261	303	315	325	334	390	464	528
Circuit 5	4,994	4,245	83	96	100	103	106	124	148	168
Circuit 6	2,621	2,228	–	–	–	–	–	–	–	–
Circuit 7	4,560	3,876	925	1,074	1,117	1,150	1,183	1,384	1,643	1,872
Circuit 8	4,641	1,795	1,044	1,212	1,261	1,299	1,335	1,562	1,855	2,114
Circuit 9	846	375	217	253	263	270	278	325	386	440
Circuit 10	2,200	85	348	404	420	433	445	520	618	704
Circuit 11	199	–	–	–	–	–	–	–	–	–
Circuit 12	3,846	85	100	100	100	100	100	100	100	100
Circuit 13	1,457	83	123	142	148	153	157	184	218	248
Circuit 14	2,504	2,129	397	461	480	494	508	594	706	804
Circuit 15	149	127	7	8	8	9	9	10	12	14
Circuit 16	2,012	598	877	1,018	1,059	1,087	1,087	1,087	1,087	1,087
Circuit 17	1,602	953	292	339	352	363	373	436	518	590
Circuit 18	2,881	624	517	600	624	642	661	773	918	1,046
Circuit 19	2,223	1,597	587	681	709	730	750	878	1,042	1,188
Circuit 20	696	272	133	154	161	165	170	199	236	269
Circuit 21	3,504	1,040	1,530	1,777	1,848	1,903	1,957	2,289	2,718	3,098
Circuit 22	2,080	85	76	88	91	94	97	113	134	153
Circuit 23	5,493	2,714	2,993	3,476	3,616	3,723	3,828	4,478	5,317	6,060
Circuit 24	2,781	851	619	719	748	771	792	927	1,101	1,254
Circuit 25	8,169	2,431	4,542	5,275	5,488	5,650	5,810	6,797	8,070	9,197
Circuit 26	1,155	–	–	–	–	–	–	–	–	–
Circuit 27	3,789	3,221	1,728	2,006	2,087	2,149	2,209	2,585	3,069	3,194
Circuit 28	5,923	5,034	1,185	1,376	1,431	1,474	1,515	1,773	2,105	2,399
Circuit 29	1,408	1,196	179	207	216	222	228	267	317	362
Circuit 30	4,644	1,857	1,758	2,042	2,124	2,187	2,249	2,631	3,124	3,560
Circuit 31	8,263	7,029	1,080	1,254	1,304	1,343	1,381	1,616	1,918	2,186
Circuit 32	6,539	5,558	231	231	231	231	231	231	231	231
Circuit 33	10,737	9,123	2,510	2,915	3,032	3,122	3,210	3,755	4,459	4,808
Circuit 34	3,243	2,756	1,124	1,305	1,358	1,398	1,438	1,682	1,997	2,276
Circuit 35	312	215	281	326	339	349	359	420	499	569
Circuit 36	3,291	1,818	812	943	981	1,010	1,038	1,137	1,137	1,137

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	841	715	109	127	132	136	139	163	194	221
Circuit 38	2,653	2,255	88	102	106	110	113	132	157	178
Circuit 39	2,479	2,107	1,006	1,168	1,215	1,251	1,287	1,505	1,787	2,037
Circuit 40	1,492	533	442	514	534	550	566	662	786	895
Circuit 41	3,459	460	631	733	762	785	807	944	1,121	1,277
Circuit 42	1,309	424	541	629	654	673	692	810	962	1,056
Circuit 43	962	81	119	138	144	148	152	178	211	241
Circuit 44	5,490	770	871	1,012	1,053	1,084	1,114	1,304	1,548	1,764
Circuit 45	1,506	764	712	827	860	885	910	1,065	1,265	1,441
Circuit 46	6,002	599	756	878	913	940	967	1,131	1,343	1,530
Circuit 47	5,097	284	298	347	361	371	382	447	530	604
Circuit 48	661	146	203	235	245	252	259	303	360	410
Circuit 49	1,526	146	144	168	174	179	184	216	256	292
Circuit 50	1,324	315	522	607	631	650	668	782	906	906
Circuit 51	1,167	2,043	1,421	1,421	1,421	1,421	1,421	1,421	1,421	1,421
Circuit 52	3,211	6,199	7,168	7,168	7,168	7,168	7,168	7,168	7,168	7,168
Circuit 53	2,988	864	1,047	1,216	1,265	1,302	1,339	1,567	1,860	2,080
Circuit 54	4,007	3,406	1,566	1,818	1,891	1,947	2,002	2,343	2,782	3,170
Circuit 55	1,677	1,425	494	574	597	614	632	739	877	1,000
Circuit 56	352	299	123	143	148	153	157	184	218	248
Circuit 57	1,035	548	429	499	519	534	549	643	763	870
Circuit 58	74	62	10	10	10	10	10	10	10	10
Circuit 59	3,462	1,758	1,648	1,914	1,991	2,050	2,108	2,466	2,928	3,337
Circuit 60	2,628	2,108	1,611	1,871	1,946	2,004	2,061	2,411	2,862	3,262
Circuit 61	1,448	1,252	945	1,097	1,141	1,175	1,209	1,414	1,679	1,913
Circuit 62	1,489	1,274	119	138	144	148	152	178	211	241
Circuit 63	1,958	940	504	586	609	627	645	754	896	1,021
Circuit 64	1,586	1,354	158	183	190	196	202	236	280	319
Circuit 65	2,879	2,471	509	591	615	633	651	762	904	1,031
Circuit 66	1,858	1,579	694	806	838	863	888	900	900	900
Circuit 67	586	498	–	–	–	–	–	–	–	–
Circuit 68	1,132	283	209	242	252	260	267	312	371	422
Circuit 69	1,920	480	402	467	486	500	514	602	714	814
Circuit 70	1,937	1,674	804	933	971	1,000	1,028	1,202	1,428	1,627
Circuit 71	2,692	2,328	400	465	484	498	512	599	711	811
Circuit 73	6,379	4,121	2,866	3,328	3,462	3,564	3,665	4,288	5,091	5,802
Circuit 74	6,752	3,386	3,543	4,115	4,281	4,407	4,532	5,302	6,295	7,174
Circuit 75	515	438	194	226	235	242	248	291	345	393

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 76	7,449	3,229	2,790	3,240	3,370	3,470	3,568	4,175	4,957	5,649
Circuit 77	851	724	597	693	721	742	763	893	1,060	1,208
Circuit 78	5,542	1,949	2,658	3,087	3,211	3,306	3,400	3,977	4,723	5,382
Circuit 79	119	76	–	–	–	–	–	–	–	–
Circuit 80	226	120	–	–	–	–	–	–	–	–
Circuit 81	1,463	480	750	871	906	933	959	1,122	1,332	1,518
Circuit 82	6,860	4,489	2,500	2,904	3,021	3,110	3,198	3,741	4,442	5,062
Circuit 83	245	208	193	224	233	240	247	289	343	391
Circuit 84	227	57	72	84	87	89	92	108	128	146
Circuit 85	676	190	189	220	229	236	242	283	337	384
Circuit 86	469	399	259	301	313	322	332	388	461	525
Circuit 87	233	198	143	167	173	178	184	215	255	291
Circuit 88	9,204	7,823	1,641	1,906	1,982	2,041	2,099	2,455	2,915	3,322
Circuit 89	2,002	1,701	860	999	1,039	1,070	1,100	1,287	1,528	1,741
Circuit 90	3,210	2,805	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Circuit 91	2,905	938	662	769	800	824	847	991	1,176	1,341
Circuit 92	376	122	147	171	178	183	188	220	261	298
Circuit 93	859	128	167	194	202	208	214	251	298	339
Circuit 94	324	117	161	187	194	200	205	240	285	325
Circuit 95	331	43	45	52	54	56	57	67	80	91
Circuit 96	1,129	219	182	211	220	226	233	272	323	369
Circuit 97	5,660	4,811	388	450	469	482	496	580	689	785
Circuit 98	4,943	4,202	374	434	452	465	478	559	664	757
Circuit 99	991	172	162	188	196	202	208	243	288	329
Circuit 100	1,001	851	270	313	326	336	345	404	479	546
Circuit 101	364	310	52	60	62	64	66	77	92	105
Circuit 102	2,812	2,390	636	738	768	791	813	951	1,129	1,287
Circuit 103	4,907	4,171	1,582	1,838	1,912	1,968	2,024	2,368	2,811	3,204
Circuit 104	4,623	2,681	2,622	3,045	3,167	3,261	3,353	3,923	4,658	5,309
Circuit 105	6,136	1,483	1,744	2,026	2,107	2,170	2,231	2,610	3,099	3,531
Circuit 106	722	171	175	203	212	218	224	262	311	355
Circuit 107	408	126	186	216	225	231	238	278	330	377
Circuit 108	311	–	–	–	–	–	–	–	–	–
Circuit 109	3,792	3,223	691	802	835	859	884	1,034	1,227	1,399
Circuit 110	5,574	4,738	272	316	329	339	349	408	484	552
Circuit 111	4,103	626	252	292	304	313	322	377	447	510
Circuit 112	4,693	3,989	1,143	1,327	1,381	1,422	1,462	1,710	2,031	2,314
Circuit 113	1,316	1,118	16	19	19	20	20	24	28	32

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 114	798	678	133	154	161	165	170	199	236	269
Circuit 115	146	124	500	500	500	500	500	500	500	500
Circuit 116	762	648	500	500	500	500	500	500	500	500
Circuit 117	2,610	836	843	979	1,018	1,048	1,078	1,261	1,497	1,706
Circuit 118	6,995	1,070	1,164	1,352	1,406	1,448	1,489	1,742	2,068	2,357
Circuit 119	2,666	585	521	605	630	648	667	780	926	1,055
Circuit 120	2,396	2,037	856	994	1,034	1,064	1,094	1,280	1,520	1,732
Circuit 121	58	–	100	–	–	–	–	–	–	–
Circuit 122	351	167	174	202	210	216	222	260	309	352
Circuit 123	944	802	150	175	182	187	192	225	267	304
Circuit 124	1,117	16	4	4	4	5	5	5	6	7
Circuit 125	3,522	1,008	883	1,025	1,066	1,098	1,129	1,321	1,568	1,787
Circuit 126	1,518	1,129	504	585	609	627	645	754	895	1,020
Circuit 127	192	163	47	54	56	58	60	70	83	95
Circuit 128	118	101	46	53	55	57	59	69	81	93
Circuit 129	1,990	1,691	1,158	1,345	1,399	1,440	1,481	1,733	2,057	2,345
Circuit 130	816	694	463	537	559	576	592	692	822	937
Circuit 131	4,112	3,495	1,038	1,206	1,254	1,291	1,328	1,553	1,844	2,102
Circuit 132	3,475	2,954	2,236	2,597	2,701	2,782	2,860	3,346	3,973	4,528
Circuit 133	1,271	–	–	–	–	–	–	–	–	–
Circuit 134	952	–	–	–	–	–	–	–	–	–
Circuit 135	698	435	255	296	308	317	326	382	453	517
Circuit 136	1,928	1,606	611	710	738	760	782	915	1,086	1,238

Table N-9. Hawai‘i Electric Light Distribution Circuit Base DG-PV Forecast (kW)

Hawai'i Electric Light Distribution Circuit High DG–PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,279	5,337	1,904	2,325	2,484	2,544	2,606	5,591	8,837	10,210
Circuit 2	1,552	1,319	534	652	697	713	731	1,568	2,478	2,933
Circuit 3	1,952	1,659	68	83	89	91	93	200	316	374
Circuit 4	2,529	2,150	420	513	548	561	575	1,234	1,950	2,308
Circuit 5	4,994	4,245	162	198	212	217	222	476	753	891
Circuit 6	2,621	2,228	68	83	89	91	93	200	316	374
Circuit 7	4,560	3,876	1,666	2,036	2,175	2,227	2,281	4,894	7,538	7,538
Circuit 8	4,641	1,795	1,310	1,600	1,709	1,750	1,793	3,846	5,416	5,416
Circuit 9	846	375	328	401	428	439	449	964	1,524	1,804
Circuit 10	2,200	85	491	600	641	656	672	1,442	2,279	2,698
Circuit 11	199	–	68	83	89	91	93	200	316	374
Circuit 12	3,846	85	136	166	178	182	186	400	632	737
Circuit 13	1,457	83	134	163	174	178	183	392	620	734
Circuit 14	2,504	2,129	756	924	987	1,011	1,036	2,222	3,512	4,157
Circuit 15	149	127	7	9	10	10	10	22	35	41
Circuit 16	2,012	598	742	907	969	992	1,016	2,180	2,610	2,610
Circuit 17	1,602	953	365	445	476	487	499	1,071	1,692	2,003
Circuit 18	2,881	624	740	904	966	990	1,014	2,174	3,437	4,068
Circuit 19	2,223	1,597	822	1,004	1,073	1,099	1,126	2,415	3,817	4,518
Circuit 20	696	272	201	246	263	269	275	591	934	1,105
Circuit 21	3,504	1,040	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223
Circuit 22	2,080	85	82	100	107	110	113	242	382	452
Circuit 23	5,493	2,714	4,517	5,517	5,895	6,036	6,183	13,265	17,295	17,295
Circuit 24	2,781	851	930	1,136	1,213	1,242	1,273	2,730	4,315	4,838
Circuit 25	8,169	2,431	6,101	7,453	7,963	8,154	8,352	16,854	16,854	16,854
Circuit 26	1,155	–	68	83	89	91	93	200	316	374
Circuit 27	3,789	3,221	2,331	2,848	3,042	3,115	3,191	6,846	6,960	6,960
Circuit 28	5,923	5,034	1,423	1,738	1,857	1,902	1,948	4,179	6,606	7,579
Circuit 29	1,408	1,196	280	341	365	374	383	821	1,298	1,461
Circuit 30	4,644	1,857	2,054	2,509	2,681	2,745	2,812	2,934	2,934	2,934
Circuit 31	8,263	7,029	1,608	1,964	2,098	2,149	2,201	4,280	4,280	4,280
Circuit 32	6,539	5,558	42	52	55	56	58	124	196	230
Circuit 33	10,737	9,123	3,416	4,172	4,458	4,565	4,676	10,031	15,856	17,214
Circuit 34	3,243	2,756	1,749	1,946	1,946	1,946	1,946	1,946	1,946	1,946
Circuit 35	312	215	389	475	507	520	532	1,142	1,230	1,230
Circuit 36	3,291	1,818	1,303	1,591	1,700	1,741	1,783	1,866	1,866	1,866

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	841	715	121	148	158	162	166	355	562	665
Circuit 38	2,653	2,255	96	117	125	128	131	282	445	527
Circuit 39	2,479	2,107	1,388	1,696	1,812	1,855	1,901	4,077	5,428	5,428
Circuit 40	1,492	533	864	1,056	1,128	1,155	1,183	2,538	3,044	3,044
Circuit 41	3,459	460	1,051	1,284	1,372	1,405	1,439	3,087	3,746	3,746
Circuit 42	1,309	424	651	795	850	870	891	1,913	3,023	3,530
Circuit 43	962	81	129	158	169	173	177	380	600	710
Circuit 44	5,490	770	1,237	1,511	1,614	1,653	1,693	3,633	5,618	5,618
Circuit 45	1,506	764	1,564	1,910	2,041	2,090	2,141	2,389	2,389	2,389
Circuit 46	6,002	599	1,149	1,404	1,500	1,536	1,573	1,887	1,887	1,887
Circuit 47	5,097	284	463	565	604	618	633	1,359	2,148	2,543
Circuit 48	661	146	271	331	354	362	371	796	1,259	1,490
Circuit 49	1,526	146	251	306	327	335	343	737	1,165	1,379
Circuit 50	1,324	315	660	806	861	882	903	1,938	3,063	3,626
Circuit 51	1,167	2,043	272	332	355	363	372	798	1,262	1,494
Circuit 52	3,211	6,199	734	896	957	980	1,004	2,154	3,405	4,031
Circuit 53	2,988	864	1,436	1,754	1,874	1,919	1,966	4,217	6,666	7,808
Circuit 54	4,007	3,406	2,184	2,668	2,851	2,919	2,990	6,416	9,266	9,266
Circuit 55	1,677	1,425	709	867	926	948	971	2,084	3,293	3,737
Circuit 56	352	299	201	246	263	269	275	591	934	1,106
Circuit 57	1,035	548	499	610	652	667	684	1,437	1,437	1,437
Circuit 58	74	62	14	17	18	18	19	40	63	75
Circuit 59	3,462	1,758	2,365	2,889	3,087	3,161	3,238	6,946	8,762	8,762
Circuit 60	2,628	2,108	2,211	2,701	2,886	2,955	3,027	6,407	6,407	6,407
Circuit 61	1,448	1,252	962	962	962	962	962	962	962	962
Circuit 62	1,489	1,274	286	349	373	382	391	776	776	776
Circuit 63	1,958	940	701	856	915	937	959	2,058	3,253	3,850
Circuit 64	1,586	1,354	218	266	284	291	298	639	1,010	1,196
Circuit 65	2,879	2,471	702	857	916	938	961	2,061	3,257	3,705
Circuit 66	1,858	1,579	735	898	959	982	1,006	2,159	2,749	2,749
Circuit 67	586	498	68	83	89	91	93	200	316	374
Circuit 68	1,132	283	283	346	370	379	388	832	1,315	1,557
Circuit 69	1,920	480	552	674	720	737	755	1,620	2,560	3,031
Circuit 70	1,937	1,674	1,040	1,270	1,357	1,390	1,424	3,054	4,135	4,135
Circuit 71	2,692	2,328	1,337	1,633	1,745	1,786	1,830	3,926	6,122	6,122
Circuit 73	6,379	4,121	3,590	4,385	4,685	4,798	4,914	10,543	14,919	14,919
Circuit 74	6,752	3,386	4,561	5,572	5,953	6,096	6,244	13,396	15,389	15,389
Circuit 75	515	438	236	288	308	315	323	693	995	995

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 76	7,449	3,229	3,942	4,816	5,145	5,269	5,397	11,578	12,755	12,755
Circuit 77	851	724	849	1,037	1,108	1,134	1,162	2,439	2,439	2,439
Circuit 78	5,542	1,949	3,631	4,436	4,739	4,853	4,971	8,743	8,743	8,743
Circuit 79	119	76	68	83	89	91	93	200	316	374
Circuit 80	226	120	68	83	89	91	93	200	316	374
Circuit 81	1,463	480	1,014	1,238	1,323	1,355	1,388	2,977	4,705	5,363
Circuit 82	6,860	4,489	3,039	3,712	3,966	4,062	4,160	8,925	10,103	10,103
Circuit 83	245	208	293	358	383	392	401	861	1,169	1,169
Circuit 84	227	57	84	102	109	112	114	245	388	459
Circuit 85	676	190	226	276	295	302	310	665	1,050	1,243
Circuit 86	469	399	420	513	548	561	575	1,234	1,545	1,545
Circuit 87	233	198	189	231	246	252	259	555	877	1,038
Circuit 88	9,204	7,823	3,236	3,953	4,224	4,325	4,430	4,930	4,930	4,930
Circuit 89	2,002	1,701	1,322	1,615	1,725	1,766	1,809	3,557	3,557	3,557
Circuit 90	3,210	2,805	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Circuit 91	2,905	938	1,038	1,268	1,354	1,387	1,421	3,047	4,817	5,702
Circuit 92	376	122	217	265	284	290	298	638	1,009	1,194
Circuit 93	859	128	201	245	262	269	275	590	933	1,104
Circuit 94	324	117	461	563	601	616	631	1,307	1,307	1,307
Circuit 95	331	43	68	83	89	91	94	201	317	375
Circuit 96	1,129	219	343	419	448	458	469	1,007	1,592	1,884
Circuit 97	5,660	4,811	501	612	654	670	686	1,472	1,559	1,559
Circuit 98	4,943	4,202	848	1,035	1,106	1,133	1,160	1,837	1,837	1,837
Circuit 99	991	172	273	333	356	365	373	801	1,266	1,499
Circuit 100	1,001	851	426	520	556	569	583	1,250	1,976	2,339
Circuit 101	364	310	80	98	104	107	109	235	371	439
Circuit 102	2,812	2,390	881	1,076	1,150	1,177	1,206	1,425	1,425	1,425
Circuit 103	4,907	4,171	2,107	2,574	2,750	2,816	2,885	6,189	7,161	7,161
Circuit 104	4,623	2,681	3,043	3,615	3,615	3,615	3,615	3,615	3,615	3,615
Circuit 105	6,136	1,483	2,274	2,777	2,968	3,039	3,113	4,984	4,984	4,984
Circuit 106	722	171	283	346	369	378	387	831	1,313	1,554
Circuit 107	408	126	202	247	264	270	277	594	701	701
Circuit 108	311	–	68	83	89	91	93	200	316	374
Circuit 109	3,792	3,223	1,406	1,409	1,409	1,409	1,409	1,409	1,409	1,409
Circuit 110	5,574	4,738	825	1,008	1,077	1,103	1,130	1,775	1,775	1,775
Circuit 111	4,103	626	521	636	679	696	713	1,472	1,472	1,472
Circuit 112	4,693	3,989	1,433	1,433	1,433	1,433	1,433	1,433	1,433	1,433
Circuit 113	1,316	1,118	17	21	23	23	24	51	81	96

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 114	798	678	185	226	241	247	253	543	858	1,016
Circuit 115	146	124	680	758	758	758	758	758	758	758
Circuit 116	762	648	680	710	710	710	710	710	710	710
Circuit 117	2,610	836	1,366	1,668	1,782	1,825	1,869	4,011	6,339	7,369
Circuit 118	6,995	1,070	2,138	2,612	2,791	2,858	2,927	6,153	6,153	6,153
Circuit 119	2,666	585	954	1,165	1,245	1,274	1,305	2,800	4,427	4,952
Circuit 120	2,396	2,037	1,299	1,587	1,696	1,736	1,778	3,815	6,031	6,571
Circuit 121	58	–	136	166	178	182	186	400	632	748
Circuit 122	351	167	271	331	353	362	371	795	1,257	1,264
Circuit 123	944	802	234	286	305	313	320	687	1,087	1,286
Circuit 124	1,117	16	679	829	886	907	929	957	957	957
Circuit 125	3,522	1,008	1,620	1,979	2,115	2,165	2,218	4,758	5,067	5,067
Circuit 126	1,518	1,129	686	838	895	917	939	2,014	3,184	3,768
Circuit 127	192	163	51	62	66	68	70	149	236	280
Circuit 128	118	101	146	179	191	196	200	430	680	805
Circuit 129	1,990	1,691	1,661	2,029	2,168	2,220	2,274	3,257	3,257	3,257
Circuit 130	816	694	744	909	971	994	1,019	1,084	1,084	1,084
Circuit 131	4,112	3,495	1,227	1,499	1,601	1,640	1,679	3,603	5,695	6,741
Circuit 132	3,475	2,954	3,196	3,904	4,171	4,271	4,375	9,235	9,235	9,235
Circuit 133	1,271	–	68	83	89	91	93	200	316	374
Circuit 134	952	–	68	83	89	91	93	200	316	374
Circuit 135	698	435	493	603	644	659	675	1,449	2,111	2,111
Circuit 136	1,928	1,606	874	1,067	1,140	1,167	1,196	2,565	4,055	4,800

Table N-10. Hawai'i Electric Light Distribution Circuit High DG-PV Forecast (kW)

INTEGRATION STRATEGY COSTS ESTIMATES

Table N–11 through Table N–45 include the annualized cost and volumes of for each integration strategy, by island, in the near–, mid–, and long–term planning horizons.

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$11,336	$3,322	$6,125	$20,784
Distribution Tsf	$12,565	$13,737	–	$26,302
OH Conductor	$1,574	$2,584	$6,480	$10,638
UG Conductor	$951	$1,547	$1,358	$3,856
Substation Tsf	$17,977	$12,433	$61,874	$92,284
46kV Grounding Tsf	$43,532	$11,048	$7,013	$61,592
Grand Total	*$87,935*	*$44,672*	*$82,850*	*$215,457*
Voltage Regulators (Qty)	259	68	99	426
Distribution Tsf (Qty)	880	880	–	1,760
OH Conductor (Ft)	7	11	20	38
UG Conductor (Ft)	1,133	1,601	1,171	3,905
Substation Tsf (Qty)	5	4	12	21
46kV Grounding Tsf (Qty)	44	10	5	59

Table N–11. O'ahu Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$116,445	$43,630	$103,495	$263,570
Replacement BESS	–	$77,815	$155,004	$232,819
Var Comp Devices	$7,300	$14,552	$27,776	$49,628.09
DER Controls	$15,792	$25,925	$42,838	$84,554
46kV Grounding Tsf	$43,532	$11,048	$7,013	$61,592
Grand Total	*$183,069*	*$172,969*	*$336,127*	*$692,165*
BESS (kW)	30,817	16,682	45,022	92,521
BESS (kWh)	123,268	66,728	180,088	370,084
Replacement BESS (kW)	–	30,817	67,523	98,340
Replacement BESS (kWh)	–	123,268	270,092	393,360
Var Comp Devices (kW)	8,283	14,383	21,861	44,527
46kV Grounding Tsf (Qty)	44	10	5	59

Table N–12. O'ahu Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Substation Tsf	$4,072	–	–	$4,072
Var Comp Devices	$3,786	$14,552	$27,776	$46,114
OH Conductor	$1,574	$2,584	$6,480	$10,638
UG Conductor	$951	$1,547	$1,358	$3,856
DER Controls	$15,792	$25,925	$42,838	$84,554
46kV Grounding Tsf	$43,532	$11,048	$7,013	$61,592
Grand Total	*$75,831*	*$55,656*	*$85,465*	*$216,952*
Voltage Regulators (Qty)	140	–	–	140
Substation Tsf (Qty)	2	–	–	2
Var Comp Devices (kW)	8,283	14,383	21,861	44,527
OH Conductor (Ft)	7,278	10,582	20,370	38,230
UG Conductor (Ft)	1,133	1,601	1,171	3,905
46kV Grounding Tsf (Qty)	44	10	5	59

Table N–13. Oʻahu Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,130	$11,260	$7,324	$30,714
Distribution Tsf	$25,237	$27,591	–	$52,828
OH Conductor	$2,454	$7,654	$15,366	$25,473
UG Conductor	$994	$6,062	$8,544	$15,600
Substation Tsf	$41,281	$138,875	$164,473	$344,629
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$129,548*	*$201,511*	*$197,113*	*$528,171*
Voltage Regulators (Qty)	270	214	107	591
Distribution Tsf (Qty)	1,770	1,770	–	3,540
OH Conductor (Ft)	11,448	30,517	50,316	92,281
UG Conductor (Ft)	1,173	6,172	7,129	14,474
Substation Tsf (Qty)	9	46	32	87
46kV Grounding Tsf (Qty)	48	9	1	58

Table N–14. Oʻahu Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,130	$11,260	$7,324	$30,714
Distribution Tsf	$25,237	$27,591	–	$52,828
OH Conductor	$2,454	$7,654	$15,366	$25,473
UG Conductor	$994	$6,062	$8,544	$15,600
Substation Tsf	$31,934	$40,316	$84,797	$157,047
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$172,761*	*$244,853*	*$181,412*	*$599,025*
Voltage Regulators (Qty)	270	214	107	591
Distribution Tsf (Qty)	1,770	1,770	–	3,540
OH Conductor (Ft)	11,448	30,517	50,316	92,281
UG Conductor (Ft)	1,173	6,172	7,129	14,474
Substation Tsf (Qty)	6	11	20	37
46kV Grounding Tsf (Qty)	48	9	1	58

Table N–15. O‘ahu Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$129,997	$381,236	$427,831	$939,064
Replacement BESS	–	$69,845	$600,370	$670,214
Var Comp Devices	$9,641	$25,831	$23,790	$59,262
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$239,649*	*$628,882*	*$1,117,372*	*$1,985,903*
BESS (kW)	27,662	118,686	148,554	294,902
BESS (kWh)	110,648	474,744	594,216	1,179,608
Replacement BESS (kW)	–	27,662	262,385	290,047
Replacement BESS (kWh)	–	110,648	1,049,540	1,160,188
Var Comp Devices (kW)	10,906	25,317	19,467	55,690
46kV Grounding Tsf (Qty)	48	9	1	58

Table N–16. O‘ahu Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$6,060	–	–	$6,060
Substation Tsf	$4,072	–	–	$4,072
Var Comp Devices	$5,522	$25,831	$23,790	$55,143
BESS	–	$17,232	$99,427	$116,659
Replacement BESS	–	–	$27,666	$27,666
OH Conductor	$2,454	$7,654	$15,366	$25,473
UG Conductor	$994	$6,062	$8,544	$15,600
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Tsf	$47,452	$10,069	$1,407	$58,927
Grand Total	*$119,113*	*$208,749*	*$240,174*	*$568,036*
Voltage Regulators (Qty)	137	–	–	137
Substation Tsf (Qty)	2	–	–	2
Var Comp Devices (kW)	10,906	25,317	19,467	55,690
BESS (kW)	–	5,083	31,056	36,139
BESS (kWh)	–	20,332	124,224	144,556
Replacement BESS (kW)	–	–	12,182	12,182
Replacement BESS (kWh)	–	–	48,728	48,728
OH Conductor (Ft)	11,448	30,517	50,316	92,281
UG Conductor (Ft)	1,173	6,172	7,129	14,474
46kV Grounding Tsf (Qty)	48	9	1	58

Table N–17. Oʻahu Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$4,720	–	–	$4,720
Distribution Tsf	$4,426	$4,839	–	$9,265
OH Conductor	$5,332	$1,901	$348	$7,582
UG Conductor	$5,114	$102	$71	$5,286
Substation Tsf	$42,704	$4,781	$5,033	$52,518
Grand Total	*$62,296*	*$11,623*	*$5,451*	*$79,370*
Voltage Regulators (Qty)	111	–	–	111
Distribution Tsf (Qty)	310	310	–	620
OH Conductor (Ft)	25,244	7,786	1,211	34,242
UG Conductor (Ft)	6,236	110	61	6,407
Substation Tsf (Qty)	16	1	3	20

Table N–18. Maui Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$69,775	$2,981	$858	$73,614
Replacement BESS	–	$45,226	$45,705	$90,931
Var Comp Devices	$8,951	$2,742	$975	$12,668
DER Controls	$564	$420	$394	$1,378
Grand Total	*$79,290*	*$51,369*	*$47,932*	*$178,591*
BESS (kW)	17,778	1,126	365	19,268
BESS (kWh)	71,111	4,503	1,459	77,074
Replacement BESS (kW)	–	17,778	19,797	37,575
Replacement BESS (kWh)	–	71,111	79,188	150,299
Var Comp Devices (kW)	10,335	2,717	814	13,866

Table N–19. Maui Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$2,903	–	–	$2,903
Substation Tsf	$42,704	–	–	$42,704
Var Comp Devices	$1,582	$2,742	$975	$5,299
OH Conductor	$5,332	$1,901	$348	$7,582
UG Conductor	$5,114	$102	$71	$5,286
DER Controls	$564	$420	$394	$1,378
Grand Total	*$58,198*	*$5,165*	*$1,788*	*$65,152*
Voltage Regulators (Qty)	69	–	–	69
Substation Tsf (Qty)	16	–	–	16
Var Compensation Devices (KW)	10,335	2,717	814	13,866
OH Conductor (Ft)	25,244	7,786	1,211	34,242
UG Conductor (Ft)	6,236	110	61	6,407

Table N–20. Maui Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$5,966	$1,741	$1,969	$9,676
Distribution Tsf	$20,369	$22,269	–	$42,638
OH Conductor	$5,975	$13,178	$16,083	$35,236
UG Conductor	$2,686	$6,171	$11,211	$20,068
Substation Tsf	$35,288	$78,174	$24,510	$137,972
Grand Total	*$70,285*	*$121,534*	*$53,773*	*$245,591*
Voltage Regulators (Qty)	140	35	32	207
Distribution Tsf (Qty)	1,429	1,429	–	2,858
OH Conductor (Ft)	27,639	53,547	52,471	133,657
UG Conductor (Ft)	3,182	6,390	9,304	18,875
Substation Tsf (Qty)	11	16	4	31

Table N–21. Maui Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$5,966	$1,741	$1,969	$9,676
Distribution Tsf	$20,369	$22,269	–	$42,638
OH Conductor	$5,975	$13,178	$16,083	$35,236
UG Conductor	$2,686	$6,171	$11,211	$20,068
Substation Tsf	$25,144	$34,587	$12,085	$71,816
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$63,764*	*$104,438*	*$56,675*	*$224,876*
Voltage Regulators (Qty)	140	35	32	207
Distribution Tsf (Qty)	1,429	1,429	–	2,858
OH Conductor (Ft)	27,639	53,547	52,471	133,657
UG Conductor (Ft)	3,182	6,390	9,304	18,875
Substation Tsf (Qty)	8	8	3	19

Table N–22. Maui Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$168,736	$216,615	$129,169	$514,520
Replacement BESS	–	$111,087	$443,313	$554,401
Var Comp Devices	$6,460	$8,913	$4,857	$20,230
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$178,820*	*$363,106*	*$592,667*	*$1,134,592*
BESS (kW)	43,825	82,679	55,747	182,252
BESS (kWh)	175,301	330,718	222,989	729,008
Replacement BESS (kW)	–	43,825	192,843	236,668
Replacement BESS (kWh)	–	175,301	771,371	946,672
Var Comp Devices (kW)	7,362	8,864	3,936	20,163

Table N–23. Maui Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$3,449	–	–	$3,449
Substation Tsf	$35,288	–	–	$35,288
Var Comp Devices	$2,519	$8,913	$4,857	$16,289
BESS	$4,210	$51,868	$67,688	$123,765
Replacement BESS	–	$2,932	$90,443	$93,374
OH Conductors	$5,975	$13,178	$16,083	$35,236
UG Conductors	$2,686	$6,171	$11,211	$20,068
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$57,750*	*$109,552*	*$205,608*	*$372,910*
Voltage Regulators (Qty)	82	–	–	82
Substation Tsf (Qty)	11	–	–	11
Var Comp Devices (kW)	7,362	8,864	3,936	20,163
BESS (kW)	1,173	20,234	29,261	50,668
BESS (kWh)	4,693	80,935	117,046	202,673
Replacement BESS (kW)	–	1,173	39,553	40,727
Replacement BESS (kWh)	–	4,693	158,214	162,907
OH Conductor (Ft)	27,639	53,547	52,471	133,657
UG Conductor (Ft)	3,182	6,390	9,304	18,875

Table N–24. Maui Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$636	–	–	$636
Distribution Tsf	$328	$358	–	$686
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$964*	*$358*	–	*$1,323*
Voltage Regulators (Qty)	15	–	–	15
Distribution Tsf (Qty)	25	25	–	50
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–25. Moloka‘i Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$3,883	$58	$98	$4,039
Replacement BESS	–	$2,499	$2,370	$4,868
Var Comp Devices	$368	$65	$30	$464
DER Controls	$16	$5	$11	$33
Grand Total	*$4,268*	*$2,627*	*$2,509*	*$9,404*
BESS (kW)	980	21	43	1,044
BESS (kWh)	3,920	85	171	4,175
Replacement BESS (kW)	–	980	1,025	2,005
Replacement BESS (kWh)	–	3,920	4,101	8,021
Var Comp Devices (kW)	424	68	24	515

Table N–26. Moloka‘i Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$420	–	–	$420
Var Comp Devices	$75	$65	$30	$170
DER Controls	$16	$5	$11	$33
Grand Total	*$511*	*$71*	*$41*	*$623*
Voltage Regulators (Qty)	10	–	–	10
Var Comp Devices (kW)	424	68	24	515

Table N–27. Moloka‘i Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$636	–	–	$636
Distribution Tsf	$2,093	$2,451	–	$4,544
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$2,729*	*$2,451*	–	*$5,181*
Voltage Regulators (Qty)	15	–	–	15
Distribution Tsf (Qty)	103	103	–	206
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–28. Moloka'i Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$636	–	–	$636
Distribution Tsf	$2,093	$2,451	–	$4,544
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
DER Controls	$100	$199	$245	$545
Grand Total	*$2,830*	*$2,650*	*$245*	*$5,725*
Voltage Regulators (Qty)	15	–	–	–
Distribution Tsf (Qty)	103	103	–	206
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–29. Moloka'i Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$5,994	$1,677	$2,080	$9,750
Replacement BESS	–	$3,954	$6,550	$10,504
Var Comp Devices	$334	$110	$77	$521
DER Controls	$100	$199	$245	$545
Grand Total	*$6,428*	*$5,941*	*$8,951*	*$21,320*
BESS (kW)	1,561	641	900	3,101
BESS (kWh)	6,242	2,562	3,599	12,403
Replacement BESS (kW)	–	1,561	2,848	4,408
Replacement BESS (kWh)	–	6,242	11,390	17,632
Var Comp Devices (kW)	377	114	61	553

Table N–30. Moloka‘i Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$420	–	–	$420
Var Comp Devices	$199	$110	$77	$386
BESS	–	–	–	–
Replacement BESS	–	–	–	–
DER Controls	$100	$199	$245	$545
Grand Total	*$720*	*$309*	*$322*	*$1,351*
Voltage Regulators (Qty)	10	–	–	10
Var Comp Devices (kW)	377	114	61	553
BESS (kW)	–	–	–	–
BESS (kWh)	–	–	–	–
Replacement BESS (kW)	–	–	–	–
Replacement BESS (kWh)	–	–	–	–

Table N–31. Moloka‘i Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	–	–	$255
Distribution Tsf	$114	$125	–	$239
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$369*	*$125*	–	*$493*
Voltage Regulators (Qty)	6	–	–	6
Distribution Tsf (Qty)	10	10	–	20
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–32. Lana'i Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$3,954	$275	$815	$5,043
Replacement BESS	–	$2,569	$2,868	$5,438
Var Comp Devices	$107	$133	$250	$490
DER Controls	$28	$26	$89	$143
Grand Total	*$4,089*	*$3,003*	*$4,022*	*$11,114*
BESS (kW)	1,010	104	355	1,470
BESS (kWh)	4,042	418	1,422	5,881
Replacement BESS (kW)	–	1,010	1,244	2,255
Replacement BESS (kWh)	–	4,042	4,976	9,018
Var Comp Devices (kW)	123	131	197	451

Table N–33. Lana'i Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$168	–	–	$168
Var Comp Devices	$36	$133	$250	$419
DER Controls	$28	$26	$89	$143
Grand Total	*$232*	*$159*	*$339*	*$730*
Voltage Regulators (Qty)	4	–	–	4
Var Comp Devices (kW)	123	131	197	451

Table N–34. Lana'i Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	$158	–	$412
Distribution Tsf	$742	$869	–	$1,610
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$996*	*$1,026*	–	*$2,023*
Voltage Regulators (Qty)	6	3	–	9
Distribution Tsf (Qty)	37	37	–	73
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–35. Lana‘i Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	$158	–	$412
Distribution Tsf	$742	$869	–	$1,610
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
DER Controls	$73	$849	$133	$1,055
Grand Total	*$1,069*	*$1,875*	*$133*	*$3,077*
Voltage Regulators (Qty)	6	3	–	9
Distribution Tsf (Qty)	37	37	–	73
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–36. Lana‘i Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$1,262	$4,962	$1,268	$7,492
Replacement BESS	–	$850	$8,062	$8,911
Var Comp Devices	$17	$143	$17	$177
DER Controls	$73	$849	$133	$1,055
Grand Total	*$1,352*	*$6,804*	*$9,479*	*$17,635*
BESS (kW)	337	1,923	532	2,791
BESS (kWh)	1,348	7,690	2,127	11,165
Replacement BESS (kW)	–	337	3,512	3,849
Replacement BESS (kWh)	–	1,348	14,049	15,396
Var Comp Devices (kW)	19	137	15	171

Table N–37. Lana'i Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$168	$158	–	$326
Var Comp Devices	$10	$143	$17	$170
BESS	–	–	–	–
Replacement BESS	–	–	–	–
DER Controls	$73	$849	$133	$1,055
Grand Total	*$251*	*$1,149*	*$150*	*$1,551*
Voltage Regulators (Qty)	4	–	–	4
Var Comp Devices (kW)	19	137	15	171
BESS (kW)	–	–	–	–
BESS (kWh)	–	–	–	–
Replacement BESS (kW)	–	–	–	–
Replacement BESS (kWh)	–	–	–	–

Table N–38. Lana'i Integration Strategy 7 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$5,054	$7,527	$5,375	$17,956
Distribution Tsf	$3,908	$1,792	$1,413	$7,113
OH Conductor	–	–	–	–
UG Conductor	–	–	–	–
Substation Tsf	–	–	–	–
Grand Total	*$8,963*	*$9,320*	*$6,787*	*$25,069*
Voltage Regulators (Qty)	72	94	54	220
Distribution Tsf (Qty)	318	126	85	529
OH Conductor (Ft)	–	–	–	–
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	–	–	–

Table N–39. Hawai'i Island Integration Strategy 1 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$32,177	$9,048	$6,975	$48,200
Replacement BESS	–	$21,656	$11,781	$33,437
Var Comp Devices	$57	–	$258	$315
DER Controls	$2,589	$4,694	$11,144	$18,426
Grand Total	*$34,822*	*$35,398*	*$30,158*	*$100,378*
BESS (kW)	8,586	3,439	2,991	15,016
BESS (kWh)	34,344	13,756	11,964	60,064
Replacement BESS (kW)	–	8,586	5,105	–
Replacement BESS (kWh)	–	34,344	20,420	54,764
Var Comp Devices (kW)	63	–	230	293

Table N–40. Hawai'i Island Integration Strategy 2 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$3,472	–	–	$3,472
Var Comp Devices	$57	–	$258	$315
DER Controls	$2,589	$4,694	$11,144	$18,426
Grand Total	$6,117	$4,694	$11,402	$22,213
Voltage Regulators (Qty)	50	–	–	50
Var Comp Devices (kW)	63	–	230	293

Table N–41. Hawai'i Island Integration Strategy 3 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$14,327	$2,107	$760	$17,194
Distribution Tsf	$1,397	$2,737	$161	$4,295
OH Conductor	$1,803	$1,492	–	$3,295
UG Conductor	–	–	–	–
Substation Tsf	$4,109	$38,258	$51,456	$93,823
Grand Total	*$21,635*	*$44,594*	*$52,377*	*$118,607*
Voltage Regulators (Qty)	191	25	8	224
Distribution Tsf (Qty)	115	195	10	320
OH Conductor (Ft)	24,159	17,652	–	41,811
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	4	26	31	61

Table N–42. Hawai'i Island Integration Strategy 4 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$14,327	$2,107	$760	$17,194
Distribution Tsf	$1,397	$2,737	$161	$4,295
OH Conductor	$1,803	$1,492	–	$3,295
UG Conductor	–	–	–	–
Substation Tsf	–	$8,794	$21,176	$29,970
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$21,890*	*$55,142*	*$51,326*	*$128,358*
Voltage Regulators (Qty)	191	25	8	224
Distribution Tsf (Qty)	115	195	10	320
OH Conductor (Ft)	24,159	17,652	–	41,811
UG Conductor (Ft)	–	–	–	–
Substation Tsf (Qty)	–	6	14	20

Table N–43. Hawai'i Island Integration Strategy 5 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$33,076	$187,013	$178,911	$398,999
Replacement BESS	–	$23,280	$254,356	$277,636
Var Comp Devices	$1,130	$94	–	$1,224
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$38,570*	*$250,398*	*$462,495*	*$751,463*
BESS (kW)	9,334	72,449	76,950	158,733
BESS (kWh)	37,336	289,796	307,800	634,932
Replacement BESS (kW)	–	9,334	110,713	120,047
Replacement BESS (kWh)	–	37,336	442,852	480,188
Var Comp Devices (kW)	1,276	93	–	1,370

Table N–44. Hawai'i Island Integration Strategy 6 Annualized Cost and Volumes

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,675	–	–	$12,675
Substation Tsf	$4,109	–	–	$4,109
Var Comp Devices	$742	$94	–	$836
BESS	–	$24,735	$46,802	$71,537
Replacement BESS	–	–	$41,189	$41,189
OH Conductor	$1,803	$1,492	–	$3,295
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$23,692*	*$66,334*	*$117,219*	*$207,244*
Voltage Regulators (Qty)	168	–	–	168
Substation Tsf (Qty)	4	–	–	4
Var Comp Devices (kW)	1,276	93	–	1,370
BESS (kW)	–	9,732	20,318	30,050
BESS (kWh)	–	38,928	81,272	120,200
Replacement BESS (kW)	–	–	18,030	18,030
Replacement BESS (kWh)	–	–	72,120	72,120
OH Conductor (Ft)	24,159	17,652	–	41,811

Table N–45. Hawai'i Island Integration Strategy 7 Annualized Cost and Volume

O. System Security

System security (or Operating Reliability) is defined by NERC as *the ability of the system to withstand sudden disturbances*.[1] These disturbances or contingencies can be the loss of generation or electrical faults that can cause sudden changes to frequency, voltage and current. Operating equilibrium following these disturbances must be restored to prevent damage to utility and end-use equipment, and to ensure public safety.

The focus of this system security analysis was on loss of generation contingency events. A full assessment of system security must evaluate steady state and transient voltage stability, rotor angle stability, and an in-depth analysis of our current under frequency load shed (UFLS) schemes; specifically how DG-PV and demand response affect the MW capacities and coordination of UFLS blocks.

How System Security is Typically Maintained

The transmission planning criteria establishes the design requirements to safely deliver real and reactive power to the distribution system. These criteria require the planning engineer to design mitigation measures to ensure system security is maintained for planned and contingency events. Some fundamental design philosophies to ensure system security include the following:

- Redundant transmission lines for capacity transfer and contingencies
- Transmission network/spatial integrity of transmission corridors
- Breaker-and- a- half or ring-bus schemes for generating units
- Limit the magnitude of the contingency

[1] NERC, *Definition of "Adequate Level of Reliability"*, December 2007, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

- Design requirements of synchronous generators (high inertia constants, high short-circuit ratio, excitation systems that are independent of system voltage, reserve capacity, etc.)
- Protective relay schemes to ensure public safety and protect equipment
- Under frequency load shed schemes to prevent system collapse and reduce restoration times

System security is maintained by operating the system with sufficient inertia, limiting the magnitude of the contingency event, maintaining adequate contingency reserves and maintaining system fault current; at times requiring the system operator to sacrifice efficiency for reliability

Inertia: the electrical system includes many rotating components which have inertia, including traditional synchronous generators (large rotating electromagnets coupled to heavy turbines or internal combustion engines), and rotating customer loads (usually induction electrical motors connected to appliances, pumps). During a contingency, the inertia in these rotating mass will resist changes to their rotational speed (i.e. limit the rate of change of frequency). Inertia, along with droop response, also provides the dampening characteristic to the frequency response profile following a contingency event as a synchronous generator continuously resists change its rotational speed. Hence, an electrical system with high inertia is more robust and can withstand contingency events better than a low inertia system.

Operational actions to protect against contingencies: 1) limit the magnitude of the disturbance; 2) reconfigure the system to mitigate risks; and 3) ensure the system is carrying the necessary contingency reserves to mitigate the adverse effects of these contingency events.

Fault protection: synchronous generators provide sufficient system fault current to activate protective relay schemes within the critical clearing times of transmission lines and generators. System fault current is also required to ensure protective relay schemes at the distribution system can detect and isolate downed power lines to ensure public safety and prevent equipment damage. Also note that an electrical system with a high capacity of fault current is less susceptible to the adverse effects of harmonic currents.

How System Security Relates to This PSIP

Resource planning must incorporate fundamental system security parameters because online resources can affect both the magnitude of the disturbance and the ability of the system to respond. For example, the size of the largest resource on the system defines the largest contingency that must be protected against, and the characteristics of available resources determine the system response.

On island systems with very high levels of wind and solar resources, the most critical security concern is displacement of thermal generators, reducing system inertia and the available system fault current.[2] This concern dominates because (a) the largest loss of generation contingency becomes a larger percentage of the total supply; and (b) the large contingency on the low inertia system will require multiple blocks of under frequency load shed (UFLS) to stabilize system frequency. While there are other potential system security concerns, such as voltage stability and reactive power capacity, mitigating these issues can be somewhat independent of the resource plan. [3] As such, this PSIP filing we will focus exclusively on determining system requirements to maintain frequency stability. Voltage stability, MVAR analysis, and rotor angle stability will be analyzed in future studies.

System security considerations are incorporated into this PSIP Update in a supportive role and do not constrain the candidate resource plans beyond limiting the magnitude of the contingency as stated above. Currently, thermal generators provide the necessary system security attributes but at some point in time, technology-neutral resources will be available in sufficient capacities to augment and replace these attributes.

Each candidate resource plan is evaluated to determine if system security requirements are met. If not, we add DR or supply-side resources to bring the plan into compliance with technology-neutral requirements.

Balancing Supply-Demand Fluctuations

Electric systems have to obey the conservation of energy law. Supply must always equal demand to maintain system frequency at 60 Hz. The automatic generation controls (AGC) must constantly dispatch regulating reserves to maintain this balance over various timeframes. As more variable resources are integrated into the system, the capacity and ramping requirements of the system's regulating reserves will increase. Similar to the issues of lower system inertia and available fault current, displacement of thermal generation reduces the online regulating reserve capacity of the system so DER/DR resource and/or central station storage will be required to maintain system frequency within acceptable limits.

Like system security, the need to balance supply and demand is incorporated into this PSIP Update. We first design resource strategies based on load and RPS requirements. We then determine if the system has adequate regulation and adequate ramping to follow net load, primarily driven by the characteristics of the variable generation resources. If regulating reserves are not adequate, technology-neutral alternatives will be added with the objective to minimize cost and other impacts of such modifications.

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[2] Low short-circuit current also affects power quality.

[3] For example, static VAR compensators can provide voltage regulation and MVAR capacity, and some inertia.

APPROACH TO ANALYZING SYSTEM SECURITY IN THIS PSIP

The process of identifying needs and designing solutions follows a several-step process that we believe addresses the Commission's concerns regarding the prior PSIP filing. (Note that this process was outlined as six steps in the Companies' February 2016 filing. The revised process is equivalent, but reorganized to complement the rest of the PSIP more clearly.) The five steps are:

1. Establish operational reliability criteria.
2. Define technology-neutral ancillary services for meeting reliability criteria.
3. Determine the amount of ancillary services needed the support the resource plan.
4. Find the lowest reasonable cost solution, considering all types of qualified resources.
5. Identify flexible planning and future analyses to optimize over time.

Step 1: Establish Operational Reliability Criteria

The ultimate criterion for system security is straightforward to specify: ensure public safety, protect utility and end-user equipment, minimize load shedding events and prevent an island-wide blackout. The original PSIP was developed to meet the requirements of HI-TPL-001.

In this PSIP Update, we revised HI-TPL-001 to focus specifically on single contingency loss of generation events to determine acceptable UFLS capacities. For O‘ahu, HI-TPL-001 was revised to no UFLS for single generator contingency events while Maui and Hawai‘i Island allow 15% system load. The Moloka‘i and Lana‘i systems were removed from HI-TPL-001 since these systems are unique island distribution systems that do not qualify as transmission systems. Further revisions to HI-TPL-001 are required for multiple contingency events, both loss of generation and/or loss of transmission elements.

Under-frequency load shedding (UFLS) is a means to restore system frequency to operating equilibrium for various loss of generation contingency events. Ultimately, it is the last line of defense of system security to prevent system blackouts but it has shortcomings for future conditions in Hawai‘i. Under high levels of distributed PV penetration, the residential load net of PV is reduced so UFLS schemes are less effective, compromising system security. Instead of disconnecting distribution circuits, future UFLS schemes must incorporate a more surgical approach to maintain sufficient capacities during the day to be effective.

Minimum Fault-Current: Electrical faults are the most severe disturbance that can cause extensive damage to equipment and pose a safety risk to the public. Protective relay schemes are designed to locate and isolate these faults within cycles to ensure equipment protection and maintain system reliability. However, if the system fault current is insufficient, protective relays cannot detect and isolate the faulted element as designed. Downed transmission lines that cannot be isolated appear as a large system load, causing localized "brown-outs" could trigger extensive UFLS. This also poses a safety risk to both equipment and the public.

Step 2: Define Technology-Neutral Ancillary Services for Meeting Reliability Criteria

Any electric system has three fundamental real power ancillary service needs, presented in order of speed of response. Only the first and third are strictly about system security, but we include all for context.

Frequency Response is needed to reduce the rate of change of frequency (RoCoF) to help stabilize system frequency immediately following a sudden loss of generation or load.

Regulation is needed to meet short-term changes in load and supply within seconds and minutes, because of solar fluctuations or the variable wind resources.

Replacement Reserves are needed to restore the faster services (above) after they are deployed, in order to be ready for the next event or further changes in net load.[4] Replacement Reserves are deployed in the minutes-to-hours timeframe and provide capacity to restore system frequency to 60 Hz following a contingency event or supplement Regulating Reserves because of forecast errors.

Other system operators define their ancillary services to serve these same basic needs, but each one's specific services depend on its system characteristics and history. The Electric Reliability Council of Texas (ERCOT) has proposed to re-design its Frequency Response as increasing renewable penetration raises new challenges in its "islanded" system separated from the rest of the mainland. However, system operators within large interconnected systems such as the Eastern Interconnection do not explicitly define Frequency Response products since the system has a vast amount of inertia to support frequency naturally.

The ancillary services products we propose for the Hawaiian Islands look like those being proposed in ERCOT, with a few additional elements to address Hawaiian-specific

[4] The North American Electric Reliability Corporation (NERC) refers to these three services as "Primary Control", "Secondary Control", and "Tertiary Control", respectively. (See NERC *Balancing and Frequency Control* Technical Document prepared by the NERC Resources Subcommittee, Jan 26, 2011.) We use the more descriptive titles for greater clarity.

needs: the small systems here are vulnerable to over-frequency in the event of a load trip. Fast Frequency Response Down would address that problem without having to rely on downward reserves from generators running at higher-than-economic output levels, as is current practice.

Table O-1, Table O-2, and Table O-3 presents the real power services proposed for Hawai‘i, along with technical specifications that any resource type would have to meet in order to provide that service.

Note that this table does not include fault-current since the protective relay schemes are designed to operate only with synchronous generators. Therefore, identifying cost effective technology-neutral ancillary services will not be pursued at this time. Fault current can be provided by online generators while they are required by the resource plan for meeting system demand and, once retired, by converting those generators to synchronous condensers that do not produce power but can provide fault current, voltage regulation, and reactive power (MVARS).

The Companies recognize that these definitions deviate from the Grid Services definitions filed in the Supplemental Report under the IDRPP (Docket No. 2007-0341) in November of 2015. These reflect further refinement to the services as defined in that filing and the Supplemental Report will be updated to reflect the refined service definitions.

Frequency Response

Reduce the rate of change of frequency (RoCoF) within cycles after a contingency, providing more time for PFR to deploy.

Frequency Response: Real-Power Ancillary Services		
Instantaneous Inertia (II)	Reduce the rate of change of frequency	
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
■ Synchronous generators (incl. pump storage) and flywheels ■ Synchronous motor loads also provide inertia; Hawaiian Electric may plan around them but wouldn't procure or control them ■ Synchronous condensers	■ Spinning mass electromagnetically coupled to grid	■ Natural characteristics of synchronous generators ■ Proportional response to changes in speed
Primary Frequency Reserves (PFR)	Stabilize frequency in either direction w/response proportional to changes in speed or frequency	
■ Synchronous generators ■ Inverter-interfaced generators and storage	■ Governor or control system meeting minimum performance requirements for droop and deadband	■ Initiation governed by deadband less than ±X Hz ■ Linear response to changes in speed or frequency ■ Time to max: a few seconds (for example, 16 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time
Fast Frequency Reserves 1 Up (FFR1Up)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Very fast-response resources (likely central station), such as batteries, flywheels, and curtailed PV	■ Control system capable of responding to signals within specified response time ■ 2-way real-time communications	■ Trigger: signal from large trip or df/dt ■ Initiation time and time to max: several cycles (for example, six cycles total reaction time, as determined by Hawai'i Electric Light contingency reserve storage study) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 10 minutes in ERCOT; 30 minute in Hawai'i Electric Light to allow replacement by gas turbine.)
Fast Frequency Reserves 2 Up (FFR2Up)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Distributed resources w/autonomous control, including DR from fairly constant loads that can curtail nearly instantaneously	■ Under-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much load is available to curtail	■ Trigger: df/dt ■ Initiation time (and time to max): a fraction of a second, but slower than FFR1 (for example, 0.5 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time and DR capabilities (for example, 1 hour in ERCOT FAS)
Fast Frequency Reserves Down (FFRDown)	Quickly restore supply-demand balance following a loss of load; reduces operational down reserves form synchronous generation	
■ Inverter-interfaced generators and storage ■ Distributed resources w/autonomous control, including DR from loads that can increase almost instantaneously	■ Over-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much generation is available to drop or load is available to increase	■ Trigger: df/dt ■ Initiation time (and time to max): a fraction of a second, similar to FFR2 (for example, 0.5 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 1 hour in ERCOT FAS)

Table O-1. Frequency Response: Real-Power Ancillary Services

Regulation

Meet second-to-second and minute-to-minute net load fluctuations around trend and forecast errors, until Replacement can take over; help restore frequency after contingencies.

Regulation: Real-Power Ancillary Services		
Regulation Reserves Up (RegUp)		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
■ Synchronous generators ■ Battery energy storage, flywheels ■ Inverter-interfaced generation (for example, curtailed wind/PV) ■ DR might meet "continuously controllable" requirements, incl. industrial loads, EVs, aggregated smaller on-off loads (e.g, heaters, compressors)	■ 2-way real-time communication to allow exchange of AGC signal and signal response with operator ■ Continuous controllability	■ Continuously follow AGC control signals with sufficient accuracy ■ Time to max: minutes (for example, 5 minutes in ERCOT) ■ Duration at max: TBD based on Replacement response time and resource capabilities (for example, 1 hour in ERCOT)
Regulation Reserves Down (RegDown)		
■ Similar to RegUp plus small load banks	■ 2-way real-time communication to allow exchange of AGC signal and signal response with operator ■ Continuous controllability	■ Similar to RegUp, but in the other direction

Table O-2 Regulation: Real-Power Ancillary Services

Replacement

Replace output of faster reserves (or restoration of shed loads) so they could deploy again; meet sustained ramps and forecast errors beyond Regulation duration.

Replacement: Real-Power Ancillary Services		
Replacement Reserves (RR)		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
■ Generators ■ DR that cannot react fast enough to provide FFR ■ Energy storage	■ One-way communication (operator to user) and controls to remotely curtail loads	■ Response time(s): TBD based on needs and resource capabilities. Consider two response times (for example, 10 and 30 minutes in ERCOT FAS) ■ Duration: TBD based on needs and resource capabilities (for example, 1 hour in ERCOT FAS) ■ Full deployment capability by the set Response Time(s) (for example, 10 minutes or 30 minutes)

Table O-3. Replacement: Real-Power Ancillary Services

Step 3: Determine the Amount of Ancillary Services Needed to Support the Resource Plan

The amounts of each type of ancillary service needed to meet system security vary by island, resource strategy, and time period. That is because Frequency Response needs are driven by the size of the largest contingency, which is generally the largest unit online at the time. Regulation needs are driven by the variability of net load (that is, load minus renewable generation output), which depends especially on the amount of PV and wind. And Replacement reserve needs are driven by the amounts of Frequency Response and Regulation needed.

Frequency Response Requirements. Our analytical methodology for determining the necessary amounts of Frequency Response services builds upon the FFR analyses performed in the Integrated Demand Response Portfolio Plan Supplement: System Response Requirements dated November 6, 2015 (Docket No. 2007-0341). In this PSIP, Fast Frequency Reserve requirements are determined for selected years for each candidate resource plan, under a range of system inertia, system load, and PFR for the largest contingency. The specific modeling approach and key assumptions are described in the next section of this appendix.

Regulation Requirements. Our methodology for determining the amount of Regulation needed is described in System Operating and Reliability Criteria in Appendix J.

Replacement Reserve Requirements. All systems currently have quick-start generation. With the addition of the Schofield units and resource plans, O‘ahu will have approximately 200 MW of quick-start generation so additional replacement reserves to supplement or displace this capacity may not be required in the near future. The system’s RR requirements are dependent on FFR and RR capacities and performance. Once these DR/DER resources have been identified and characterized, RR capacities can be evaluated and technology-neutral resource benefits quantified.

Fault Current Requirements. Hawaiian Electric’s Transmission Planning Criteria for Stability Analysis requires modeling of common N-1 and N-2 electrical faults to maintain system stability. Simulations were performed to determine the MVA capacity required to meet minimum fault current levels for three phase, line-to-line, and single line to ground faults are established for each substation 46kV bus. . This ensures proper operation of protective relay schemes.

For the Maui and Hawai‘i Island systems, the minimum fault current requirements at the distribution substations have not been determined. Therefore, the MVA capacities provided by the current must-run thermal units will be maintained.

Step 4: Find Lowest Reasonable Cost Solution Considering All Types of Qualified Resources

All of the Ancillary Service needs are defined in technology-neutral terms so any qualified resource can meet them, whether traditional generation, advanced features of inverter-interfaced generation and storage, or demand response. Our objective is to identify the lowest reasonable cost combination that ensures system security for a given resource plan and in subsequent iterations, let the market and specific resource applications determine available resources. To do so, we break the analysis into three steps:

1. Construct an initial pre-DR solution that meets system security needs;
2. Substitute DR to the full extent it is cost-effective, producing a revised resource strategy;
3. Consider whether the solution would affect system conditions (especially unit commitment and dispatch, affecting inertia and the amount of PFR available) to warrant another iteration of analysis.

As stated earlier, thermal units are required to provide system fault current from 2016 through a period of time when retired units can be converted to synchronous condensers as dictated by the resource plan. To reduce potential curtailment in the interim, fossil fired steam units can operate in in VPO[5] if available.

We develop the initial pre-DR solution to meet the Frequency Response requirement as follows (recall that the Frequency Response need was reduced to an FFR requirement, as described in the prior step): In the pre-DR solution, we first assess how much FFR2 is required to meet HI-TPL-001. We then determine if FFR2 capacities are sufficient and if not, evaluate alternatives to meet system security requirements. This could be to limit the magnitude of the contingency, supplement FFR2 with increased system inertia (operate units in VPO if available), or supplement FFR2 with FFR1.

The initial pre-DR solution meets Regulation needs from the lowest-cost available resources by including regulation as a minimum "spinning reserve" constraint in the dispatch model. If not enough regulation is available, batteries or other resources are added. Note that these needs have already been met before determining Frequency Response needs and solutions.

Once we have a pre-DR solution that meets system security, we determine how much DR can meet the AS technical requirements and cost-effectively substitute for the pre-DR resources.

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[5] Variable Pressure Operation entails partial burner operation with lower operating pressures. This lowers the operating load at the expense of lower or negligible reserve capacities for dispatch.

Finally, after having added DR and other resources to support system security, we assess whether another iteration of system security analysis is warranted. For example, if the amount of synchronous generation decreases substantially, more FFR or system inertia may be needed.

Step 5: Identify Flexible Planning and Future Analyses to Optimize Over Time

The PSIP provides a framework to support future decision-making, not a set-in-stone plan. It recognizes the need for flexibility. It recognizes that actual future procurement decisions will incorporate new information and sharpen specific analyses that are not practical or appropriate for the PSIP. But the PSIP can identify ways to maintain flexibility, and future developments to look for, and some of the analyses to conduct when decisions have to be made.

Future analyses may include the following:

- Steady state load flow and transient analysis tools to transmit DER to the transmission system
- Damping of oscillatory instabilities for a low-inertia system. Siemens PSS®E is limited to point in time contingency events and is not suited to analyze instability caused by frequency oscillations
- Power quality impacts to the transmission system
- Smart inverter controls and characteristics required to meet system security
- Effects of Rapid Transit in O‘ahu

Some of these analyses will require modeling tools and/or outside support.

MODELING ASSUMPTIONS FOR ANALYZING FREQUENCY RESPONSE

Overview of Modeling Approach

We use the Siemens PSS®E power flow model, Version 33.7, to analyze system security following a contingency. The analysis starts with the hourly load and generation data from the production cost simulations. It also incorporates data on the physical characteristics of all of the generators (i.e., capacities and H-constants determining inertia, and ramp rates), loads, and transmission and distribution elements. The equations in the model reflect the physical operation of an AC power system, including the response of relays and equipment to changes in system conditions. We are thereby able to simulate system stability immediately following the generation contingency. We focus the analysis on two informative hours, which we select using a one-bus simplified version of PSSE: a "typical hour" when the probability of the contingency event is relatively high, and a "boundary" hour when the contingency event is more severe but the probability is low. For each of these hours, we analyze in detail the frequency response reserve requirements to meet TPL-001.

Modeling of Specific Types of Elements

The following assumptions are common across cases:

- The kinetic energy for each generator was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. For the system, the total kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.
- Loads are modeled to have a frequency dependence of 1%. This equates to a 1% decline in real power consumption for a 1% drop in frequency. For example, in a 1000 MW system, load will decrease by 10 MW for a system frequency of 59.4 Hz, a decrease of 0.6 Hz. This relationship is attributed to the makeup of the system load, with a portion of it consisting of motor loads. The frequency response from motor loads is about equal to 1 to 2 percent of load.
- Legacy PV inverters are those inverters that have already been installed in Hawai'i that have an operating range of 59.3 Hz to 60.5 Hz. The table below shows the assumptions made as to the amount of inverters that still have these frequency ranges. These figures were estimated by the Companies based on a review of the inventory of installed inverters and what ride through standards applied to these inverters. If a contingency drives system frequency outside of this range, inverters are required to disconnect from the system within 0.16 seconds (for simplicity, legacy PV is modeled to disconnect immediately). The capacity of legacy PV that would disconnect at 60.5 Hz is higher than the capacity that at 59.3 Hz, as shown in Table 4 below. In the simulations, the amount of generation lost is less than the nameplate capacity to the extent that PV capacity factors are below 100% for the simulated hour. All other DG-PV will continue generating if frequency remains between 56 Hz to 64 Hz.

Legacy PV Capacities					
ISLAND	O'ahu	Hawai'i	Maui	Moloka'i	Lana'i
Size PV Systems (kW) @ 59.3 Hz	73,824	4,781	6,743	811	96
Size PV Systems (kW) @ 60.5 Hz	105,691	30,599	29,853	1,920	227

Table O-4. Estimated Legacy PV Capacities

To simulate the performance of autonomous-controlled inverter-based systems, DER resources are modeled with droop response. Droop response is inversely proportional to the system's frequency response profile so this resource would be characterized as PFR.

Fast frequency response one (FFR1) was modeled as a step change to full output within 12-cycles to simulate Auto-scheduling control of a battery energy storage system (BESS). In Auto-scheduling control, the BESS will receive a command to dispatch to full output on an open-breaker signal from AES or Kahe 5/6. Fast frequency response two (FFR2) was modeled as a df/dt initiated response in 30-cycles to simulate Demand Response load control technology in the near future. For both FFR1 and FFR2, we assumed the capacity would be available for the duration of the event until the system is stable (approximately 30 minutes). Otherwise, loss of this capacity could trigger a secondary contingency event. (If supplemental reserves from Demand Response are available, the duration of FFR can be reduced.)

Screening Tool

A screening tool was created to address the probability of a contingency event occurring for any given case. A simplified system network model was created in PSS®E to accept input data from the hourly production cost simulation data for each plan. Automation of the model is implemented using Python[6]. The entire network impedance structure was collapsed into an equivalent single bus system. Therefore, the screening method does not take into account network effects such as voltage variations across the system. The focus of this analysis is the loss of generation contingency event so the key metric is the frequency nadir[7] due to MW imbalances. Voltage issues will be addressed in future analyses.

The screening tool estimates the system frequency response to a generator trip for each hour of the year and is not meant to replicate a fully detailed simulation. The frequency nadir is calculated by PSS®E based on a trip of the largest loaded unit for every hour in the study year. The frequency nadir data is processed in Excel to produce charts to graphically illustrate the estimated risk to the system.

[6] Python is a high level, dynamic, object-orient programming language that can be utilized to automate or customize PSSE study procedures.

[7] The lowest frequency point at which the frequency decline is arrested.

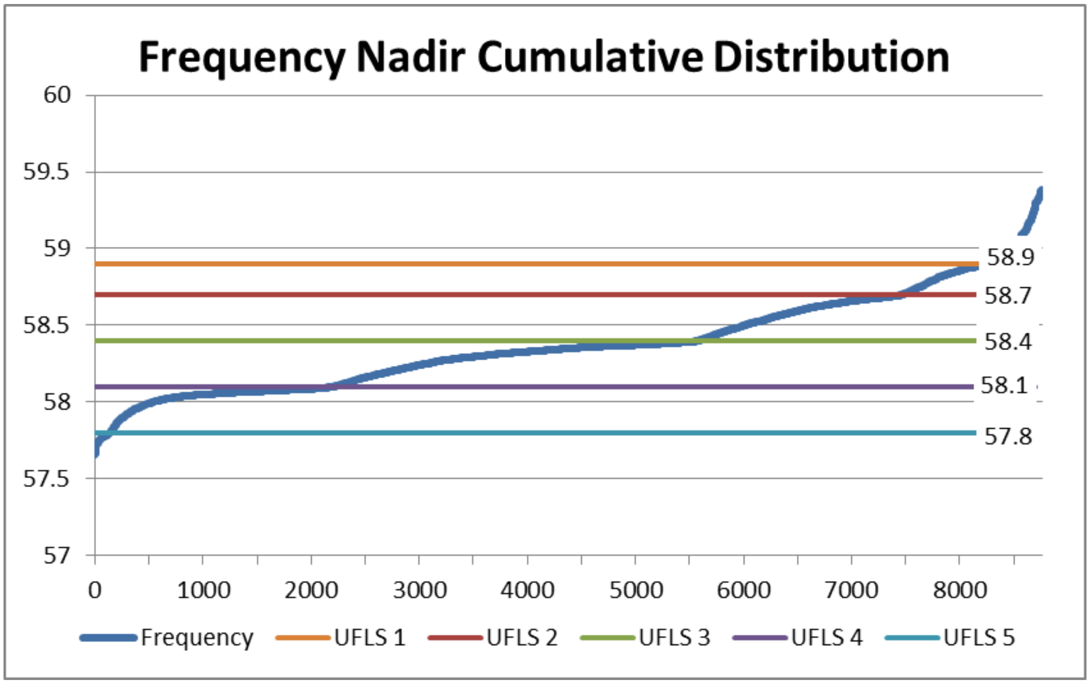


Figure O-1. Frequency Nadir Duration Curve

Figure O-1 shows the duration curve of the frequency nadirs for all the hours in 2023. The horizontal lines show the UFLS blocks for O'ahu. The example chart above shows that we will are exposed to tripping UFLS block 1 (58.9Hz) for about 8,000 hours of the year. Furthermore, for roughly 2,000 hours in the year, we are exposed to tripping UFLS block 4 (58.1 Hz) indicating a significantly risk to the system.

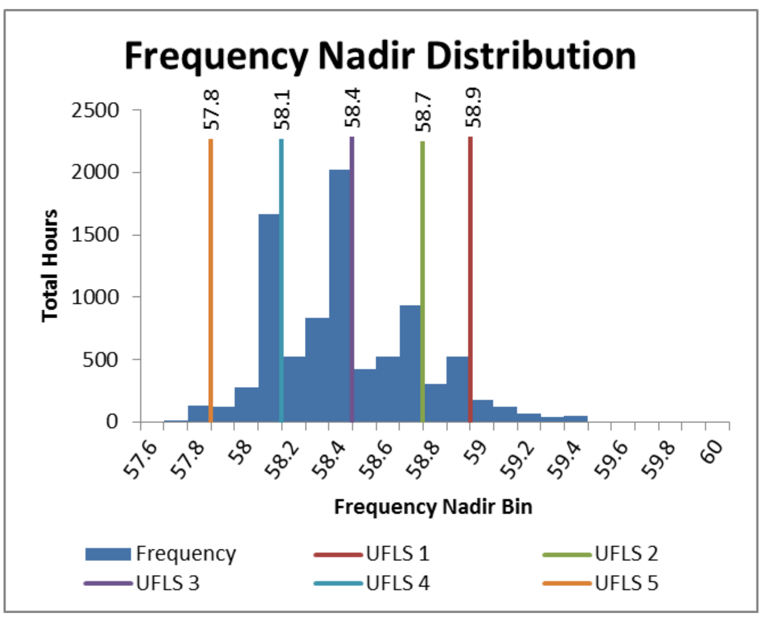


Figure O-2. Frequency Nadir Histogram

Figure O-2 shows the hourly distribution of the frequency nadirs as a result of loss of generation contingency events for 2023. The same source data for the chart above was used to generate this chart, which grouped the nadir data in 0.1Hz frequency buckets.

Using the frequency nadir distribution chart, two hours are selected for further analysis using the full PSS®E system model. The first hour is chosen by selecting a severe nadir from a large frequency grouping that can occur more frequently in the year (large bar on graph, with significant blocks load shed).

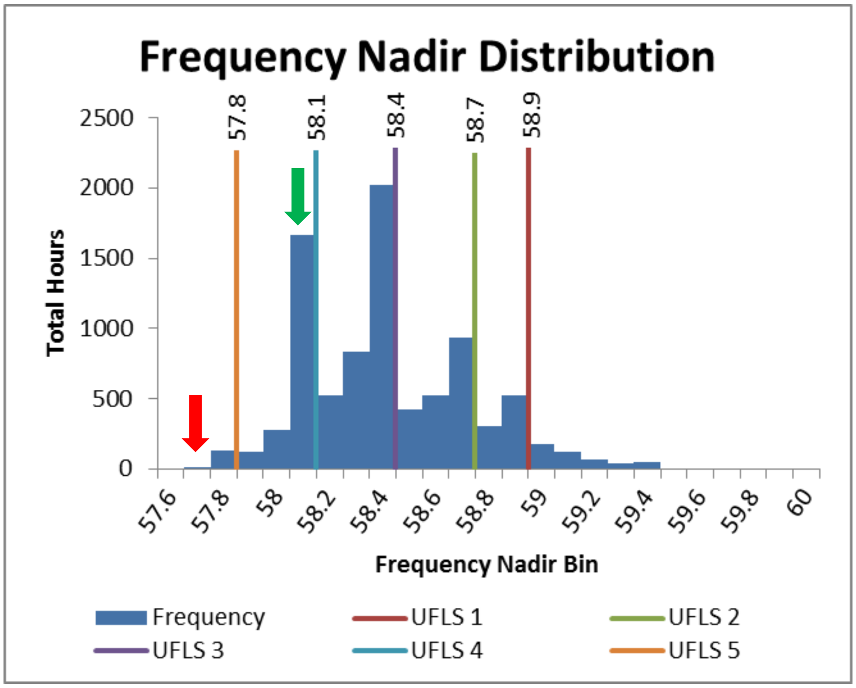


Figure O-3. Frequency Nadir Histogram – Selection

Figure O-3 illustrates the selection of hours for more detailed analysis. The green arrow represents a typical hour for a range of frequency nadirs from 58.0 - 58.1 Hz that could occur 1636 hours in 2023. The red arrow represents a boundary hour for a range of frequency nadirs from 57.6 - 57.8 Hz that could occur 129 hours in 2023. The selected hours are further analyzed using the comprehensive PSS®E database.

Additional screening was performed for the Hawai'i Electric Light analysis to evaluate loss of DG-PV due to the increased exposure to transmission system faults that cause transient voltage issues.

Limitations of Modeling Simulations

Production Cost simulations optimize system performance and cannot take into account operational changes to mitigate system risks. For example, it's typical for system operators to commit non-economic units to mitigate system risks when transmission lines are taken out of service for maintenance.

Dynamic models are a critical component of transient analyses. Governor and exciter models with default settings are adequate for simulating system contingency events when many units are running. As more units are taken offline, more sophisticated dynamic governor and exciter models may be required. This is also true for dynamic models for central station PV and wind turbine models provided by independent power producers.

Distributed PV is currently modeled as negative loads. Advanced inverter models are being developed and will be available in 2016 after which advanced inverter functions and any benefits they provide can be captured.

O'AHU CANDIDATE PLANS

Before analyzing future system security needs, we examine the current state of the system. We start with an assessment of recent historical events, followed by a projection of system security preparedness for 2016. We also include in this section an assessment of system security needs for 2019, since that is very early in the planning horizon, before the candidate resource plans diverge. The candidate plans will be assessed in the following section of this appendix.

State of the System

The O'ahu system is currently at risk because of the proliferation of DG-PV. Distributed PV poses the biggest challenge to system security because it imposes fundamentally conflicting requirements on the electrical system; 1) the reduction of system load displaces synchronous generators and 2) DG-PV increases regulating and contingency reserve requirements that are traditionally provided by synchronous generators. More specifically, transformation of the electrical system must address the following system security issues:

- DG-PV displaces synchronous generators that provide essential grid services like inertia, regulating reserves, and system fault current
- DG-PV reduces the capacity of the system's under frequency load shed scheme (UFLS)
- Legacy DG-PV increases the magnitude of a loss of generation contingency
- DG-PV is currently an uncontrollable and invisible resource

The design of O'ahu's electrical system is based on the inherent characteristics of synchronous generators. A synchronous generator is basically a large rotating magnet that provides essential grid services like inertia and fault current to the system; two critical parameters required to maintain system stability. As synchronous generators are cycled offline to make room for as-available resources, the stability margin of the system is reduced and we begin to approach the stability limits of the system.

Besides the loss of these stability parameters, lower daytime loads increases the magnitude of the generation contingency. Prior to the proliferation of DG-PV, an AES trip at full output typically represented 15 – 18% of the system generation. Today, an AES trip combined with loss of generation from legacy PV can represent 30% - 35% of the typical daytime load, doubling the magnitude of the contingency event.

Lower system inertia and the larger magnitude contingency increases the rate of change of frequency (RoCoF), reducing the time for traditional governor droop and demand response to arrest the decay in system frequency. Analysis of recent AES trip events confirms that O'ahu's electrical system is operating with a smaller stability margin and is relying on multiple blocks of UFLS to help stabilize system frequency.

The UFLS scheme is designed to stabilize system frequency for severe loss of generation contingency events and acts as a last resort system preservation scheme to prevent an island-wide blackout. Under frequency load shed schemes are implemented in blocks of load. These load shed blocks are coordinated to shed increasing amounts of load at various frequency settings, progressively increasing the amount of load shed as for lower system frequency nadirs. The intent is to preserve the system for the low probability/high impact contingency events or unforeseen cascading events.

Under frequency load shedding must characterize load to shed low impact loads and avoid critical load like hospitals, emergency responders, schools, etc. Unfortunately, the proliferation of DG-PV is primarily on these residential distribution circuits so the daytime UFLS capacities for Blocks 1-3 continue to degrade and it's becoming more difficult to find residential load to shed. Demand Response will have a similar impact on UFLS schemes except load shed capacities in Blocks 4 and 5 will also be decreased.

Historical Contingency Events on Oahu

O'ahu has experienced several AES trip events over the past two years that required multiple blocks of UFLS to stabilize system frequency. On June 9, 2014, AES experienced a turbine trip at full output that resulted in an effective loss of 198 MW. With the additional loss of 50 MW of generation from Legacy PV, the contingency event was 248 MW that represents a 30% loss of generation. The system was carrying 310 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in less than 3 seconds. Three blocks of UFLS (approximately 110 MW) were initiated to stabilize system frequency.

On July 22, 2015, AES experienced a turbine trip at full output that resulted in an effective loss of 201 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 256 MW that represents a 29% loss of generation. The system was carrying 283 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in 3.25 seconds. Three blocks of UFLS (approximately 82 MW) were initiated to stabilize system frequency.

On July 23, 2015, AES experienced a breaker trip at full output that resulted in an effective loss of 180 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 235 MW that represents a 28% loss of generation. The system was carrying 297 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.5 Hz in less than 3 seconds. Three blocks of UFLS (approximately 82 MW) were initiated to stabilize system frequency.

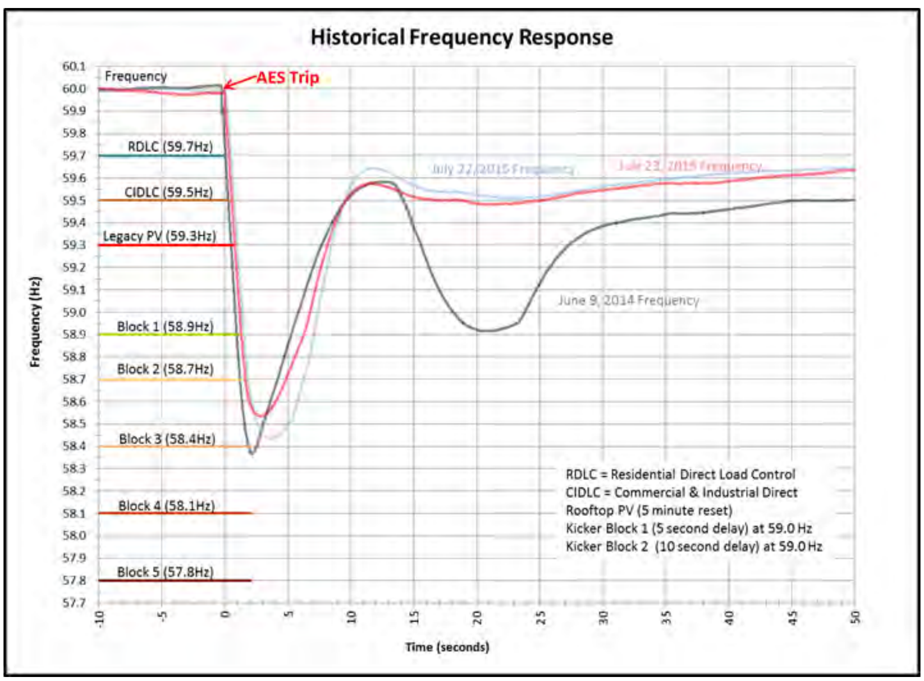


Figure O-4. Frequency Response Profile of Historic Contingency Events

Figure O-4 shows the frequency response profiles of these events.

	June 9, 2014 Event 9:49 AM	July 22, 2015 Event 11:23 AM	July 23, 2015 Event 11:22 AM
System Load	830 MW	890 MW	850 MW
Generator Units On-Line	K1, K2, K3, K4, K5, K6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP
Total Kinetic Energy	6233	6059	6059
Synchronous Inertia Response	211	169	197
AES Gross MW Loss of Generation	198 MW	198 MW	180 MW
Excess Spinning Reserve	130 MW	103 MW	117 MW
Excess Quick Load Pick Up	50 MW	72 MW	78 MW
Estimated PV Tripped at 59.3Hz	50 MW	56 MW	55 MW
Frequency Nadir	58.4 Hz	58.4 Hz	58.5 Hz
Rate of Change of Frequency*	-0.94	-0.75	-0.84
Number of UFLS Blocks Shed	Blocks 1-3 (96 MW) & Block 5 (13.5 MW)**	Kicker Block 1 (20 MW) & Blocks 1-2 (62 MW)	Kicker Block 1 (20 MW) & Blocks 1-2 (65 MW)
*Note: Circuit in Block 5 tripped causing additional load shed			

Table O-5. Historical Contingency Events

Table O-5 shows the system characteristics of the historical system events.

Frequency Response Analysis for O'ahu in 2016

System security analysis was performed on two hours that were selected from the Theme 3 production cost simulations that represents a typical hour and a boundary condition.

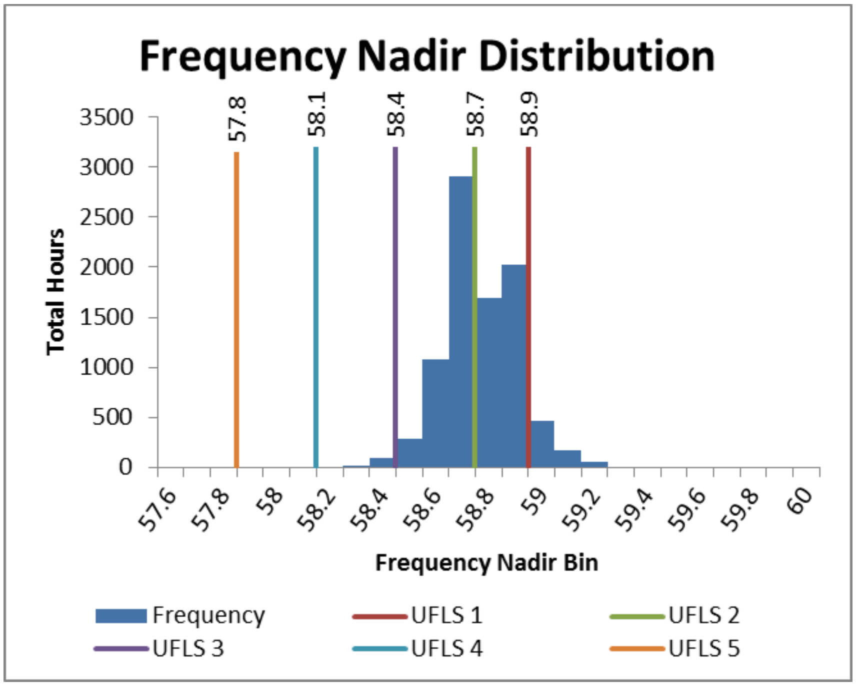


Figure O-5. Frequency Nadir Histogram 2016

Figure O-5 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year in 2016. This figure shows the probability distribution of the number of hours in the year where a N-1 generator contingency event would result in a drop to the frequency nadir. The typical hour selected from the maximum distribution of 2904 hours was 1:00 PM on Monday, October 10. The frequency nadir range for the typical hour is 58.6 – 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 99 hours was 2:00 PM on Sunday, April 10. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

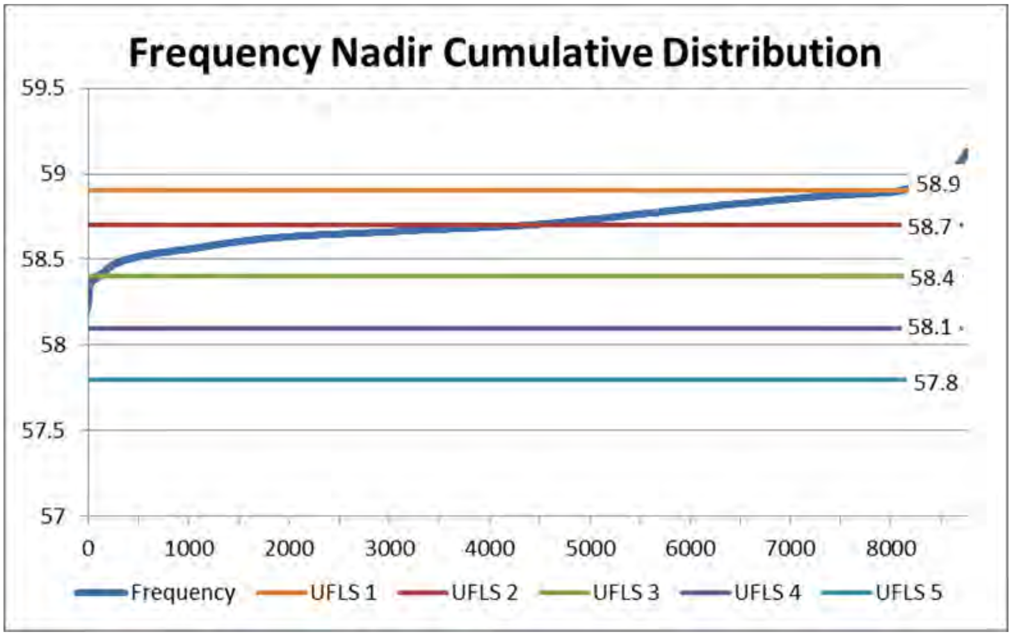


Figure O-6. Frequency Nadir Distribution Curve 2016

Figure O-6 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings							HECO 2016 (Typical) Mon 10/10/16 Hour 13			HECO 2016 (Boundary) Sun 4/10/16 Hour 14		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	41.0	5.0	16.0	44.0	2.0	19.0
HPOWER-2	22.5	10.0			3.41	42.1	144				10.0	12.5	0.0
AES	180.0	63.0			2.57	239.0	614	180.0	0.0	117.0	180.0	0.0	117.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	81.0	3.0	52.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	37.0		27.0	40.0	0.0	30.0
Kahe 5	134.6	64.7			4.36	158.8	692	64.7	69.9	0.0	64.7	69.9	0.0
Kahe 6	133.8	63.9			4.36	158.8	692	63.9	69.9	0.0			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	26.0	60.2	2.3	18.0	0.0	13.0
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	26.0	59.3	2.4	8.0	0.0	3.0
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	26.0	56.2	2.2	10.0	0.0	5.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	19.0	0.0	14.0	5.0	0.0	0.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	81.0	3.0	52.0	84.0	0.0	55.0
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	23.0	0.0	18.0	7.0	0.0	2.0
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	26.0	57.3	2.2			
Waiau 5	54.5	23.5			4.07	64.0	261	23.5	31.0	0.0	25.0	29.5	1.5
Waiau 6	53.7	23.8			4.00	64.0	256	23.8	29.9	0.0			
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447	5.9	44.0	0.0	5.9	44.0	0.0
Waiau 9	52.9	5.9			7.84	57.0	447						
Total Wind	99	0						12			23		
-Kahuku	30	0						4			11		
-Kawailoa	69	0						8			12		
DG-PV	447	0						331			281		
Station PV	10	0						10			7		
Total Kinetic Energy									7059			5828	
Total Load									1100			897	
Total Thermal Generation									748			586	
Total Renewable Generation									353			311	
Total Generation									1101			897	
Excess Generation									1			0	
Total Up Regulation									489			158	
Total Down Regulation									305			301	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		54.7	59.3Hz Output		46.4
	60.5Hz Capacity			105.7				60.5Hz Output		78.3	60.5Hz Output		66.4

Table O-6. Unit Commitment and Dispatch 2016

Table O-6 shows the unit commitment and dispatch schedules for the typical hour (10/16/2016 at 1:00 PM) and boundary hour (4/10/2016 at 2:00 PM).

Loss of Generation

Simulations were performed to determine system performance for the largest loss of generation contingency for the typical and boundary hours. For O'ahu, this is an AES turbine trip at full output and the subsequent loss of generation from legacy PV.

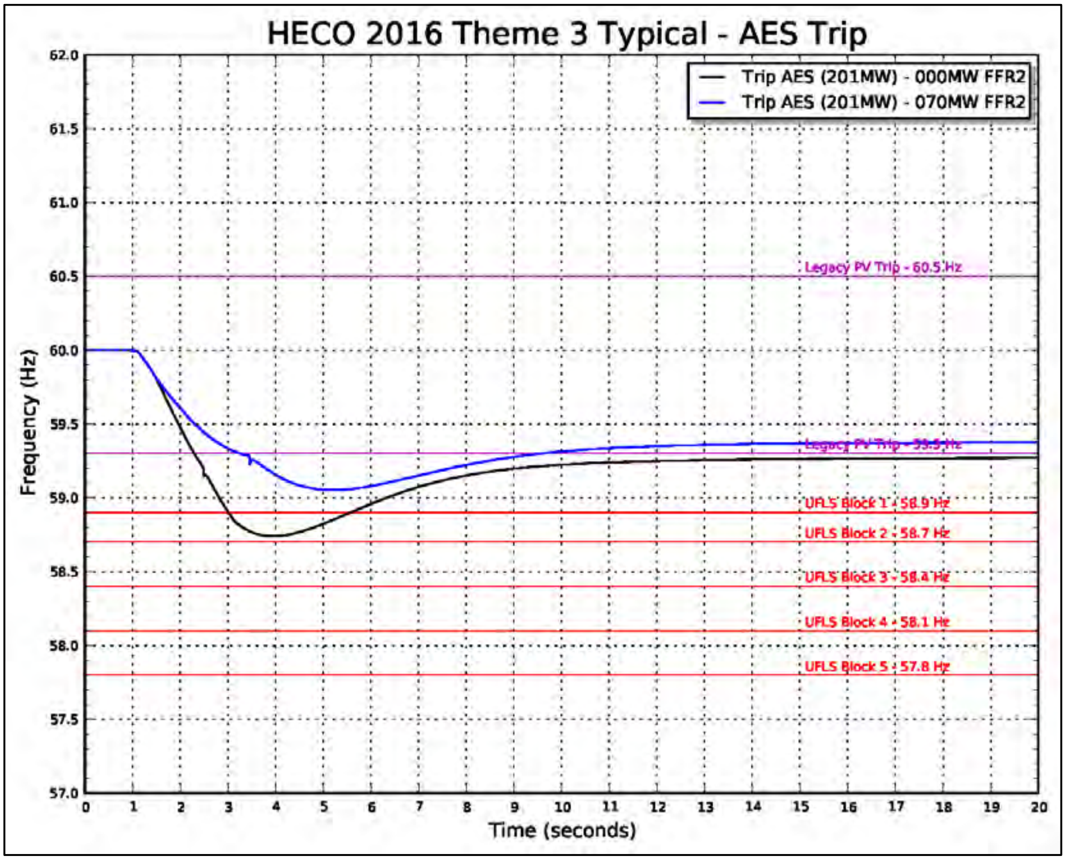


Figure O-7. Frequency Response Profile FFR2 Typical Hour

Figure O-7 shows the frequency response profile for an AES turbine trip for a typical hour. System kinetic energy is 7059 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 55 MW. With no FFR, the frequency nadir is 59.8 Hz, and one block of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001, no UFLS, is 70 MW.

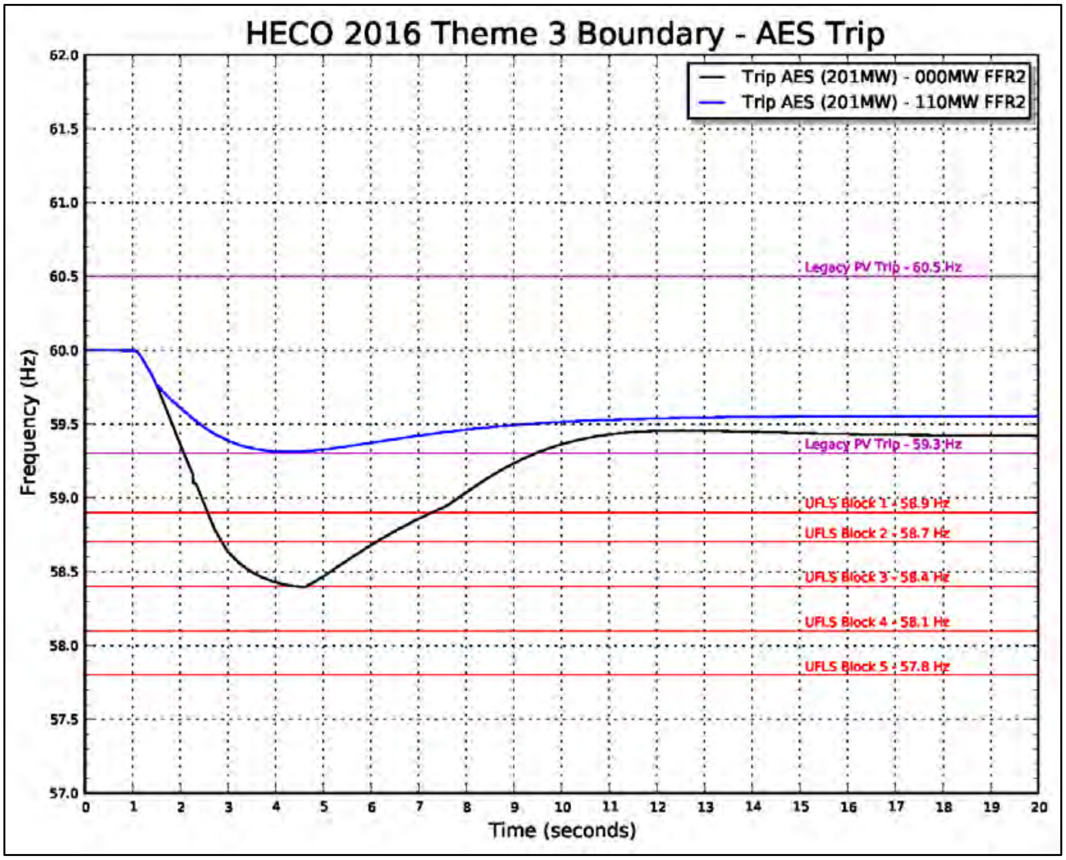


Figure O-8. Frequency Response Profile FFR2 Boundary Hour

Figure O-8 shows the frequency response profile for the boundary hour. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

Fault Current Analysis for 2016

Simulations were performed for three phase-to-ground, two phase-to-ground, single phase-to-ground, and line-to-line faults for different unit commitment schedules while monitoring 46kV bus currents. Units were cycled offline until one or more of the Minimum Acceptable Fault Current Limits from Table O-7 were violated.

The unit commitment schedule that meets the Minimum Acceptable Fault Current Limits was HPOWER 1, HPOWER 2, AES, and Kahe 5 with a total of 515 MVA fault current capacity. Any combination of synchronous generating units or synchronous condensers that total 515 MVA will provide sufficient fault current to ensure proper operation of relay protection schemes.

PSSE BUS	46kV Bus #	Circuit Name	Circuit Breaker
ARCH46A	4101	Archer 42A	6041
ARCH46A	4101	Archer 41	6043
ARCH46B	4102	Archer 43	6051
ARCH46B	4102	Archer 44A	6053
ARCH46C	4103	Archer 46	6072
HLWA46A	4121	Halawa 1	4865
HLWA46A	4121	Halawa 2	4864
HLWA46B	4122	Halawa 3	4863
HLWA46B	4122	Halawa 4	4883
SCH 46A	4181	School - Puunui	4582
SCH 46B	4182	School - Nuuanu	4409
IWI 46A	4131	Iwilei 1	4401
IWI 46B	4132	Iwilei 2	4402
KOOL46D	4154	Koolau - Kahuku	4464
KOOL46A	4151	Koolau - Wailupe 1	4467
KOOL46B	4152	Koolau - Wailupe 2	4477
KOOL46C	4153	Koolau - Aikahi	4465
KOOL46A	4151	Koolau - Kaneohe	4466
KOOL46C	4153	Koolau - Nuuanu - Laelae	4484
KOOL46D	4154	Koolau - Pohakupu	4469
KOOL46B	4152	Koolau - Kailua	4414
PUKE46A	4171	Pukele 1	4813
PUKE46B	4172	Pukele 3	4815
PUKE46C	4173	Pukele 5	4820
PUKE46C	4173	Pukele 6	4817
PUKE46D	4174	Pukele 7	4818
PUKE46D	4174	Pukele 8	4819
MAKA46A	4161	Makalapa 42	5133
MAKA46C	4163	Makalapa 46	5128
WHWA46A	4191	Wahiawa - Waialua 2	4683
WHWA46C	4193	Wahiawa - Milikua	4621
WHWA46B	4192	Wahiawa - Mililani	4448
WHWA46C	4193	Wahiawa - Waimano	4449
KAHE46B	4142	Kahe - Mikilua	4714
KAHE46A	4141	Kahe - Standard Oil 1	4717
KAHE46B	4142	Kahe- Standard Oil 2	4715
KAHE46A	4141	Kahe - Permanente	4716
CEIP46A	4111	CEIP 42	5156

PSSE BUS	46kV Bus #	Circuit Name	Circuit Breaker
CEIP46C	4113	CEIP 45	5159
CEIP46C	4113	CEIP 46	5160
EWAN46A	4341	Ewa Nui 41	5338
EWAN46A	4341	Ewa Nui 42	5339
WAIAU46	4201	Waiau - Steel Mill	4653
WAIAU46	4201	Waiau - Barbers Point	4486
WAIAU46	4201	Waiau - Mililani	4453

Table O-7. Minimum Fault Current (1 of 3)

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
3372	3380	IWILEI-AIRPORT 1	3364	3740	IWILEI-AIRPORT 1
3330	3380	IWILEI-AIRPORT 1	3444	3740	IWILEI-AIRPORT 1
3376	3406	IWILEI-AIRPORT 1	3515	3771	IWILEI-AIRPORT 1
3371	3406	IWILEI-AIRPORT 1	3500	3771	IWILEI-AIRPORT 1
2591	3382	IWILEI-AIRPORT 1	2171	3742	IWILEI-AIRPORT 1
2834	3887	HALAWA-KAHE AB 1	2242	4192	HALAWA-KAHE AB 1
2704	3887	HALAWA-KAHE AB 1	2068	4192	HALAWA-KAHE AB 1
2596	3880	HALAWA-KAHE AB 1	1901	4184	HALAWA-KAHE AB 1
2894	3880	HALAWA-KAHE AB 1	2247	4184	HALAWA-KAHE AB 1
8366	8944	IWILEI-AIRPORT 1	7154	10093	IWI 46A-SCH 46B 1
7034	8944	IWILEI-AIRPORT 1	5565	10093	IWI 46A-SCH 46B 1
5476	8961	IWILEI-AIRPORT 1	3751	10388	IWILEI-AIRPORT 1
6375	8961	IWILEI-AIRPORT 1	4577	10388	IWILEI-AIRPORT 1
1002	3606	HALAWA-KOOLAU 1	600	4027	HALAWA-KOOLAU 1
1832	3658	HALAWA-KOOLAU 1	1186	3977	HALAWA-KOOLAU 1
1926	3636	HALAWA-KOOLAU 1	1245	3951	HALAWA-KOOLAU 1
2599	3603	HALAWA-KOOLAU 1	2014	3913	HALAWA-KOOLAU 1
2220	3658	HALAWA-KOOLAU 1	1561	3977	HALAWA-KOOLAU 1
2633	3603	HALAWA-KOOLAU 1	2056	3913	HALAWA-KOOLAU 1
2095	3606	HALAWA-KOOLAU 1	1409	4027	HALAWA-KOOLAU 1
2027	3636	HALAWA-KOOLAU 1	1385	3951	HALAWA-KOOLAU 1
3115	3760	KOOLAU-PUKELE 2	2649	4140	KOOLAU-PUKELE 2
2732	3784	KOOLAU-PUKELE 2	2119	4168	KOOLAU-PUKELE 2
2497	3814	KOOLAU-PUKELE 2	1823	4205	KOOLAU-PUKELE 2
2373	3814	KOOLAU-PUKELE 2	1696	4205	KOOLAU-PUKELE 2
2806	3731	KOOLAU-PUKELE 2	2176	4104	KOOLAU-PUKELE 2

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
3040	3731	KOOLAU-PUKELE 2	2475	4104	KOOLAU-PUKELE 2
4816	6483	MAKALAPA-WAIAU 2	3516	6717	MAKALAPA-WAIAU 2
5730	6435	MAKALAPA-WAIAU 2	4860	6585	MAKALAPA-WAIAU 2
921	3547	WAHIAWA-WAIAU 1	512	4238	WAHIAWA-WAIAU 1
1433	3516	WAHIAWA-WAIAU 1	927	4006	WAHIAWA-WAIAU 1
2814	3627	WAHIAWA-WAIAU 1	2289	4625	WAHIAWA-WAIAU 1
2048	3516	WAHIAWA-WAIAU 1	1417	4006	WAHIAWA-WAIAU 1
1708	3647	CEIP-KAHE CD 1	1293	3854	CEIP-KAHE CD 1
2541	3828	CEIP-KAHE CD 1	2489	4057	CEIP-KAHE CD 1
1693	3647	CEIP-KAHE CD 1	1276	3854	CEIP-KAHE CD 1
2205	3828	CEIP-KAHE CD 1	1290	4057	CEIP-KAHE CD 1
3224	3663	CEIP-AES 2	2618	3868	CEIP-AES 2
3264	4185	CEIP-AES 2	3473	4460	CEIP-AES 2
2441	4185	CEIP-AES 2	1461	4460	CEIP-AES 2
2646	3755	CEIP-EWA NUI 1	1951	4138	CEIP-EWA NUI 1
2843	3755	CEIP-EWA NUI 1	2247	4138	CEIP-EWA NUI 1
2655	6411	KALAE-AES 1	1659	7209	KALAE-AES 1
3994	6411	KALAE-AES 1	2793	7209	KALAE-AES 1
1748	6411	KALAE-AES 1	1122	7209	KALAE-AES 1

Table O-8. Minimum Fault Current (2 of 3)

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
3415	4185	IWILEI-AIRPORT 1	2920	2927	IWILEI-AIRPORT 1
3501	4185	IWILEI-AIRPORT 1	2883	2927	IWILEI-AIRPORT 1
3568	4223	IWILEI-AIRPORT 1	2924	2950	IWILEI-AIRPORT 1
3548	4223	IWILEI-AIRPORT 1	2919	2950	IWILEI-AIRPORT 1
2495	4188	IWILEI-AIRPORT 1	2244	2929	IWILEI-AIRPORT 1
2665	4550	HALAWA-KAHE AB 1	2451	3366	HALAWA-KAHE AB 1
2492	4550	HALAWA-KAHE AB 1	2338	3366	HALAWA-KAHE AB 1
2370	4540	HALAWA-KAHE AB 1	2245	3360	HALAWA-KAHE AB 1
2677	4540	HALAWA-KAHE AB 1	2503	3360	HALAWA-KAHE AB 1
8062	11219	IWI 46A-SCH 46B 1	7217	7746	IWILEI-AIRPORT 1
6570	11219	IWI 46A-SCH 46B 1	6071	7746	IWILEI-AIRPORT 1
4966	12313	IWI 46A-SCH 46B 1	4730	7760	IWILEI-AIRPORT 1

Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario	Minimum Acceptable Fault Current (Amps) [1]	Fault Current (Amps)	Line out Scenario
5805	12313	IWI 46A-SCH 46B 1	5504	7760	IWILEI-AIRPORT 1
925	4559	HALAWA-KOOLAU 1	868	3123	HALAWA-KOOLAU 1
1659	4358	HALAWA-KOOLAU 1	1587	3168	HALAWA-KOOLAU 1
1737	4327	HALAWA-KOOLAU 1	1668	3149	HALAWA-KOOLAU 1
2368	4281	HALAWA-KOOLAU 1	2251	3120	HALAWA-KOOLAU 1
2022	4358	HALAWA-KOOLAU 1	1922	3168	HALAWA-KOOLAU 1
2436	4281	HALAWA-KOOLAU 1	2280	3120	HALAWA-KOOLAU 1
1894	4559	HALAWA-KOOLAU 1	1814	3123	HALAWA-KOOLAU 1
1842	4327	HALAWA-KOOLAU 1	1755	3149	HALAWA-KOOLAU 1
2945	4605	KOOLAU-PUKELE 2	2695	3256	KOOLAU-PUKELE 2
2527	4640	KOOLAU-PUKELE 2	2364	3277	KOOLAU-PUKELE 2
2285	4685	KOOLAU-PUKELE 2	2160	3303	KOOLAU-PUKELE 2
2164	4685	KOOLAU-PUKELE 2	2054	3303	KOOLAU-PUKELE 2
2592	4561	KOOLAU-PUKELE 2	2428	3231	KOOLAU-PUKELE 2
2844	4561	KOOLAU-PUKELE 2	2630	3231	KOOLAU-PUKELE 2
4425	6968	MAKALAPA-WAIAU 2	4164	5614	MAKALAPA-WAIAU 2
5549	6743	MAKALAPA-WAIAU 2	4952	5572	MAKALAPA-WAIAU 2
352	5264	WAHIAWA-WAIAU 1	797	3072	WAHIAWA-WAIAU 1
683	4655	WAHIAWA-WAIAU 1	1240	3045	WAHIAWA-WAIAU 1
1931	6381	WAHIAWA-WAIAU 1	2434	3141	WAHIAWA-WAIAU 1
1082	4655	WAHIAWA-WAIAU 1	1772	3045	WAHIAWA-WAIAU 1
1042	4087	CEIP-KAHE CD 1	1478	3158	CEIP-KAHE CD 1
1978	4316	CEIP-KAHE CD 1	2182	3315	CEIP-KAHE CD 1
1025	4087	CEIP-KAHE CD 1	1465	3158	CEIP-KAHE CD 1
949	4316	CEIP-KAHE CD 1	1855	3315	CEIP-KAHE CD 1
3003	4096	CEIP-AES 2	2788	3172	CEIP-AES 2
3051	4774	CEIP-AES 2	2798	3624	CEIP-AES 2
2160	4774	CEIP-AES 2	2046	3624	CEIP-AES 2
2427	4609	CEIP-EWA NUI 1	2288	3252	CEIP-EWA NUI 1
2660	4609	CEIP-EWA NUI 1	2459	3252	CEIP-EWA NUI 1
2412	8233	KALAE-AES 1	2297	5552	KALAE-AES 1
3627	8233	KALAE-AES 1	3452	5552	KALAE-AES 1
1655	8233	KALAE-AES 1	1513	5552	KALAE-AES 1

Table O-9. Minimum Fault Current (2 of 3)

Note 1 = Minimum Acceptable Fault Current provided by Protection group

Simulations were performed for electrical faults on the 138 kV transmission system busses. A three-phase fault was placed on 28 busses to evaluate system performance to normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2016 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Stable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Stable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Stable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Stable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Stable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Stable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Stable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Stable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-10. Summary of Results for the Fault Analysis

Table O-10 shows the results of the breaker failure analysis. For the typical hour, 4 simulations resulted in unstable operation and for the boundary hour, 14 simulations resulted in unstable operation. In all simulations, HPOWER loses synchronism with the system.

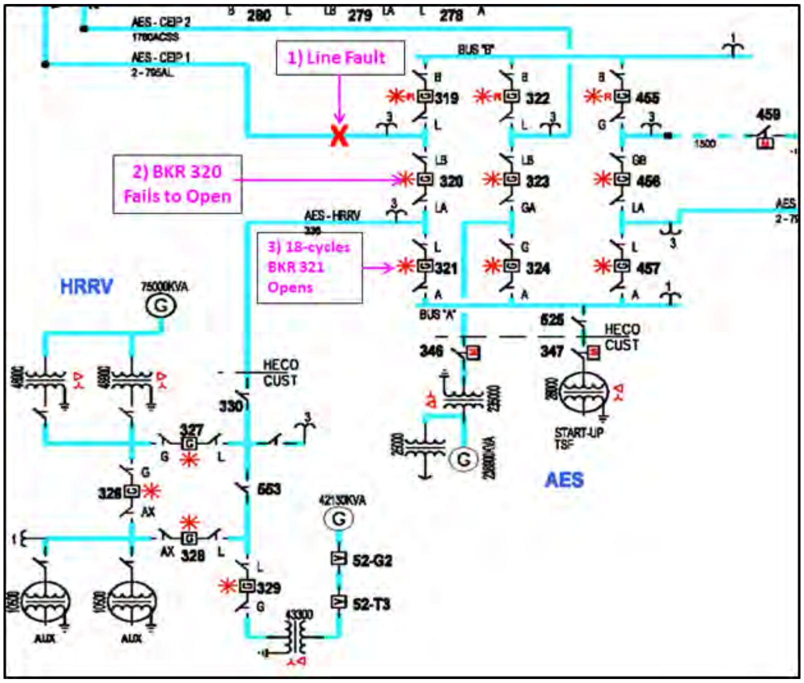


Figure O-9. Breaker Failure Diagram

Figure O-9 is a diagram that illustrates the breaker failure simulation. 1) A three-phase fault is placed on the AES-CEIP 1 transmission line; 2) BKR 320 fails to open; 3) BKR 321 opens 18-cycles later.

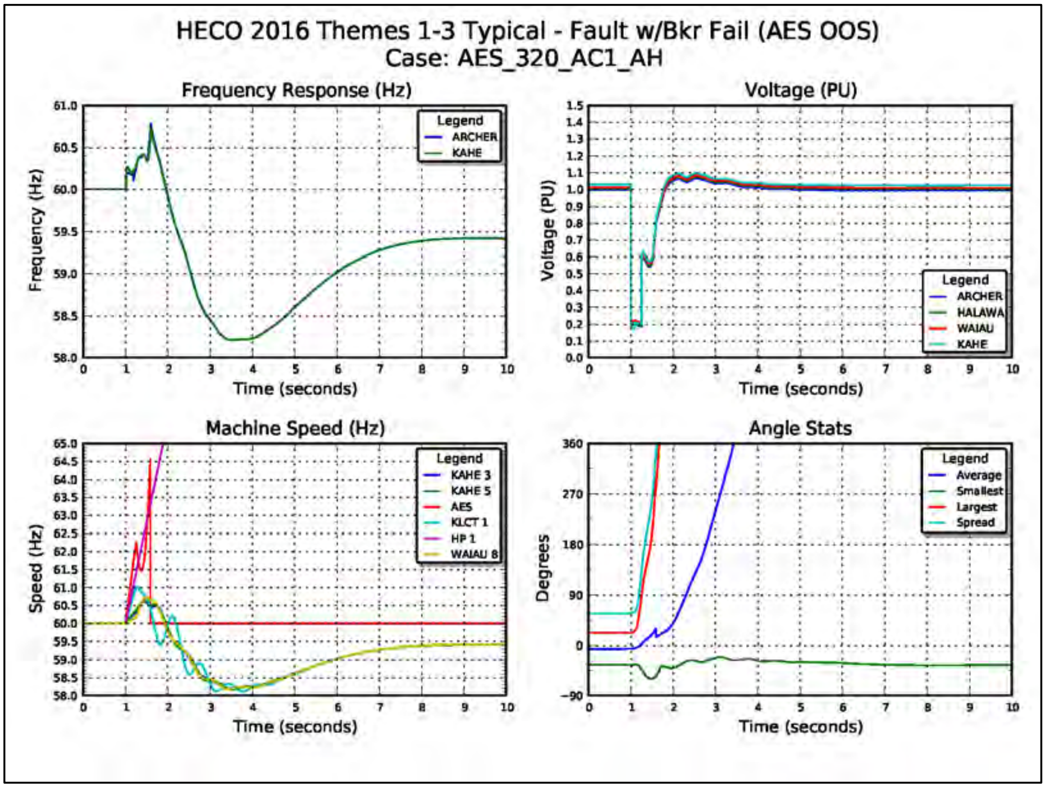


Figure O-10. System Performance for BKR 320 Failure Analysis

Figure O-10 shows four plots that illustrate unstable operation for a fault on the AES-CEIP 1 line and BKR 320 fails to operate. The Machine Speed plot shows AES (red) begin to accelerate before tripping while HPOWER 1 (magenta) loses synchronism with the system. This occurs when an electrical fault cannot be cleared before the critical clearing time of a generator, causing these units to accelerate and slip a pole. Both AES and HPOWER 1 have low inertia constants (2.78 and 2.57 MJ/MVA respectively) that determines the shorter critical clearing times of these units. AES has out of step relay protection but HPOWER 1 and HPOWER 2 do not. More analysis is required to determine mitigation alternatives.

2019 – Compliance with TPL-001

System security analysis was performed on two hours that were selected from the Theme 3 production cost simulations that represents a typical hour and a boundary condition.

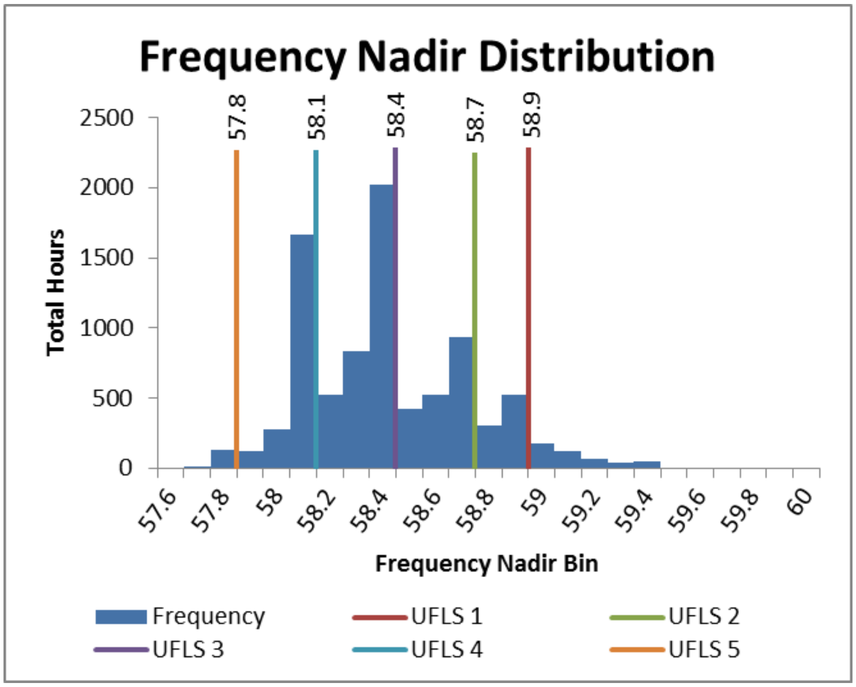


Figure O-11. Frequency Nadir Histogram for 2019

Figure O-11 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. The typical hour was selected from the maximum distribution of 1665 hours was 1:00 PM on Friday, September 6. The frequency nadir range for the typical hour is 58.0 - 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 5 hours was 1:00 PM on Saturday, January 26. The frequency nadir range for the boundary hour is 57.6 – 57.7 Hz that requires five blocks of UFLS to stabilize system frequency.

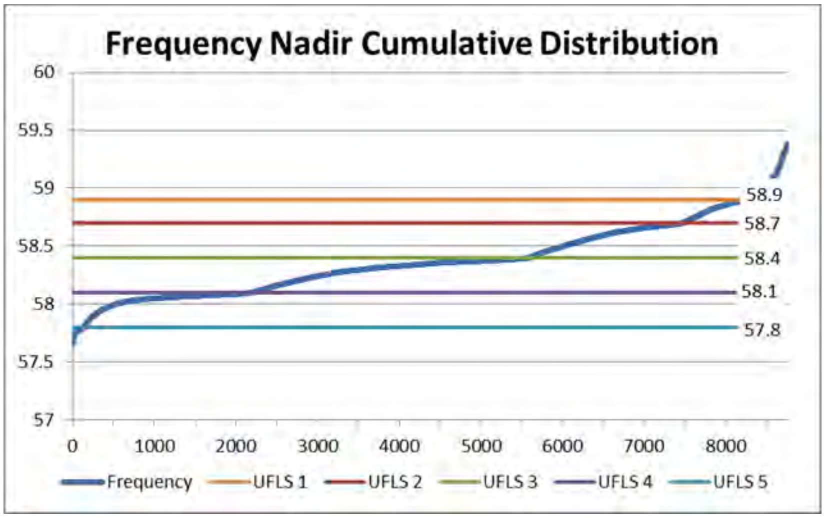


Figure O-12. Frequency Nadir Duration Curve 2019

Figure O-12 shows the frequency nadir duration curve for 2019.

Unit Commitment Order	Unit Ratings							Theme 3 - HECO 2019 (Typical) Fri 9/6/19 Hour 11			Theme 3 - HECO 2019 (Boundary) Sat 1/26/19 Hour 13		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	41.0	5.0	16.0
HPOWER-2	22.5	10.0			3.41	42.1	144	18.0	4.5	8.0			
AES	180.0	63.0			2.57	239.0	614	180.0	0.0	117.0	180.0	0.0	117.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0		30.0			
Kahe 5	134.6	64.7			4.36	158.8	692	64.7	69.9	0.0	64.7	69.9	0.0
Kahe 6	133.8	63.9			4.36	158.8	692	63.9	69.9	0.0	71.0	62.8	7.1
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						28			38		
-Kahuku	30	0						6			4		
-Kawailoa	69	0						13			10		
-Na Pua Makani	24	0						8			21		
-Future Wind	10	0						1			3		
DG-PV	664	0						438			366		
Station PV	163	0						132			130		
Total Kinetic Energy									4070			2457	
Total Load									1179			891	
Total Thermal Generation									581			357	
Total Renewable Generation									598			534	
Total Generation									1179			891	
Excess Generation									0			0	
Total Up Regulation									144			138	
Total Down Regulation									286			140	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		48.7	59.3Hz Output		40.7
	60.5Hz Capacity			105.7				60.5Hz Output		69.7	60.5Hz Output		58.3

Table O-11. Commitment and Dispatch 2019

Table O-11 shows the unit commitment and dispatch for the typical hour (9/16/2019, 11:00 AM) and boundary hour (1/26/2019, 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

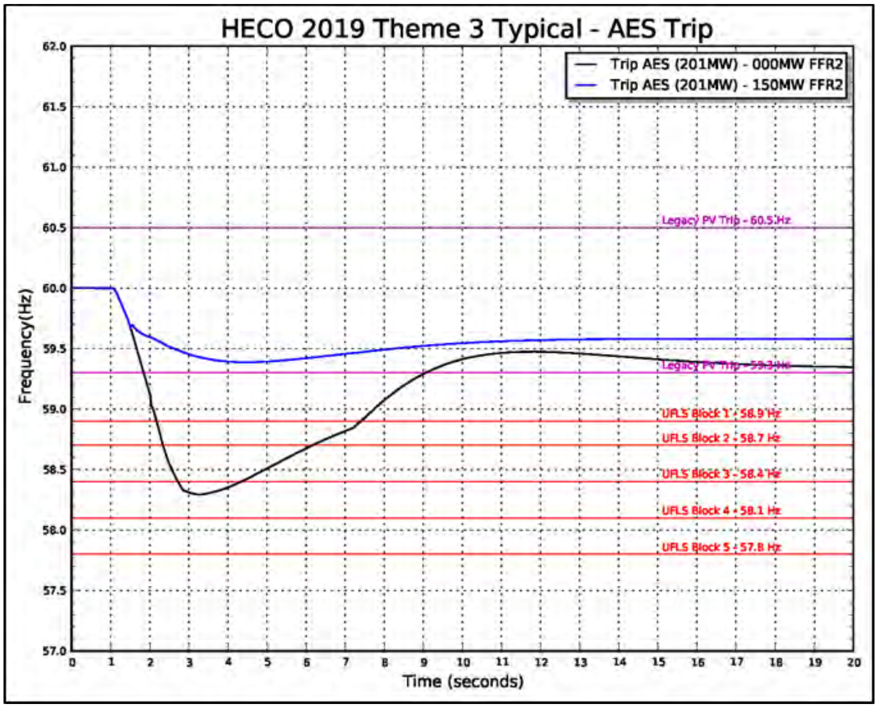


Figure O-13. Frequency Response Profile for FFR2 Typical Hour

Figure O-13 shows the frequency response profile for an AES turbine trip for a typical hour. System kinetic energy is 4070 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 49 MW. With no FFR2, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR2required, which Demand Response could be used to meet this capacity, to bring the system into compliance with TPL-001 is 150 MW.

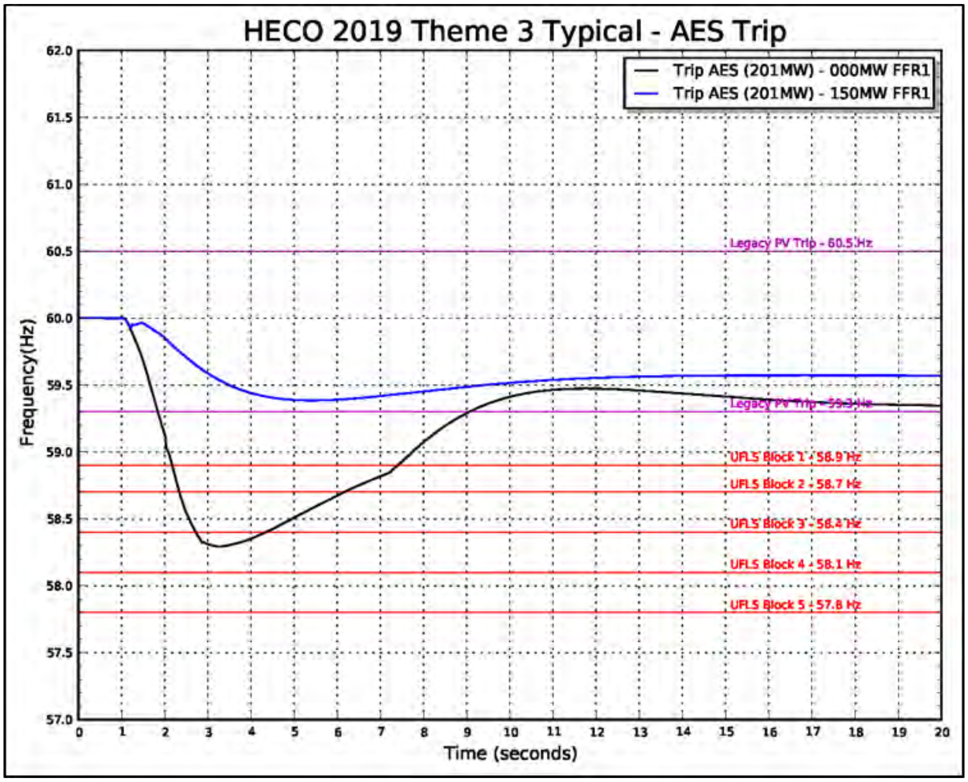


Figure O-14. Frequency Response Profile for FFR1 Typical Hour

Figure O-14 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

The frequency response profiles are results from the simulations for the typical hour.

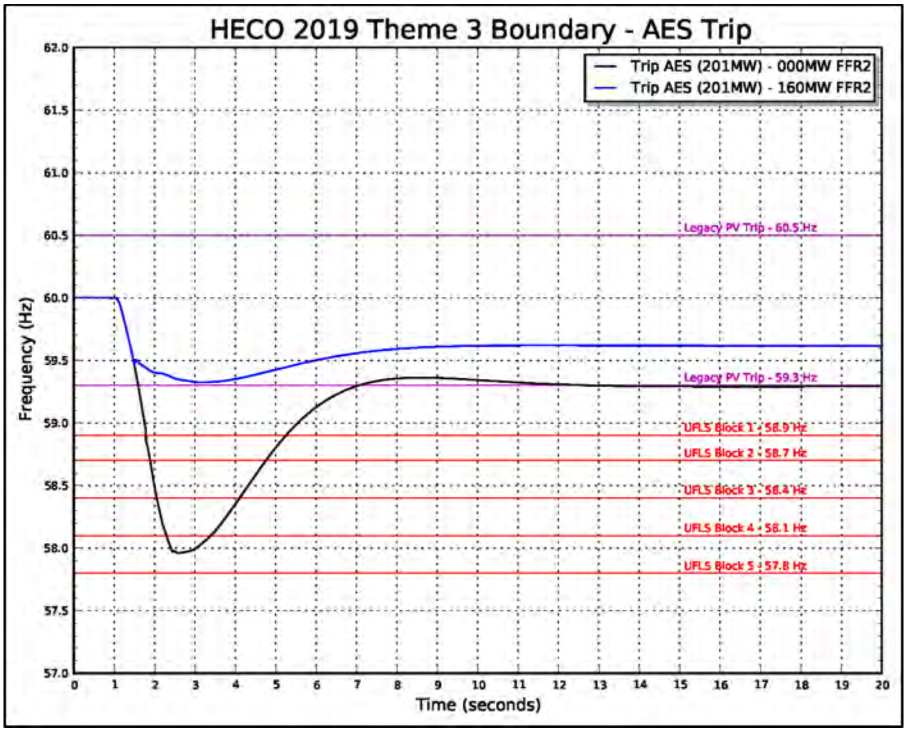


Figure O-15. Frequency Response Profile for FFR2 Boundary Hour

Figure O-15 shows the frequency response profile for an AES turbine trip for a boundary hour. System kinetic energy is 2457 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 41 MW. With no FFR, the frequency nadir is 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 160 MW.

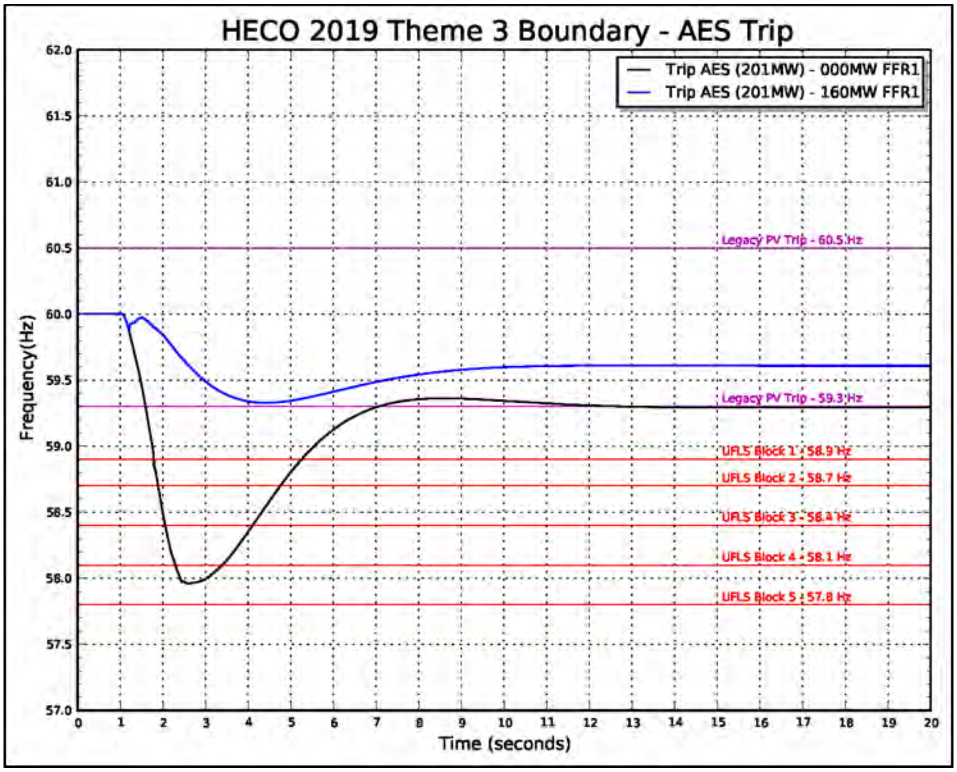


Figure O-16. Frequency Response Profile for FFR1 Boundary Hour

Figure O-16 shows the frequency response profile for this analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 160 MW.

2019 Sensitivity Analysis

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe 5 or 6 at 134.6 MW.

Unit Commitment Order	Unit Ratings							Theme 3 - HECO 2019 (Typical) Fri 9/6/19 Hour 11 [AES at 134MW]			Theme 3 - HECO 2019 (Boundary) Sat 1/26/19 Hour 13 [AES at 134MW]		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	41.0	5.0	16.0
HPOWER-2	22.5	10.0			3.41	42.1	144	18.0	4.5	8.0			
AES	180.0	63.0			2.57	239.0	614	134.0	46.0	71.0	134.0	46.0	71.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0		30.0			
Kahe 5	134.6	64.7			4.36	158.8	692	87.7	46.9	23.0	87.7	46.9	23.0
Kahe 6	133.8	63.9			4.36	158.8	692	86.9	46.9	23.0	94.0	39.8	30.1
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						21%	28		29%	38	
-Kahuku	30	0							6			4	
-Kawailoa	69	0							13			10	
-Na Pua Makani	24	0							8			21	
-Future Wind	10	0							1			3	
DG-PV	664	0						66%	438		55%	366	
Station PV	163	0						81%	132		80%	130	
Total Kinetic Energy									4070			2457	
Total Load									1179			891	
Total Thermal Generation									581			357	
Total Renewable Generation									598			534	
Total Generation									1179			891	
Excess Generation									0			0	
Total Up Regulation									144			138	
Total Down Regulation									286			140	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		48.7	59.3Hz Output		40.7
	60.5Hz Capacity			105.7				60.5Hz Output		69.7	60.5Hz Output		58.3

Table O-12. Unit Commitment and Dispatch Sensitivity

Table O-12 shows the revised dispatch for this analysis. The output of AES was reduced to 134 MW and the outputs of Kahe 5 and Kahe 6 were increased to meet system load.

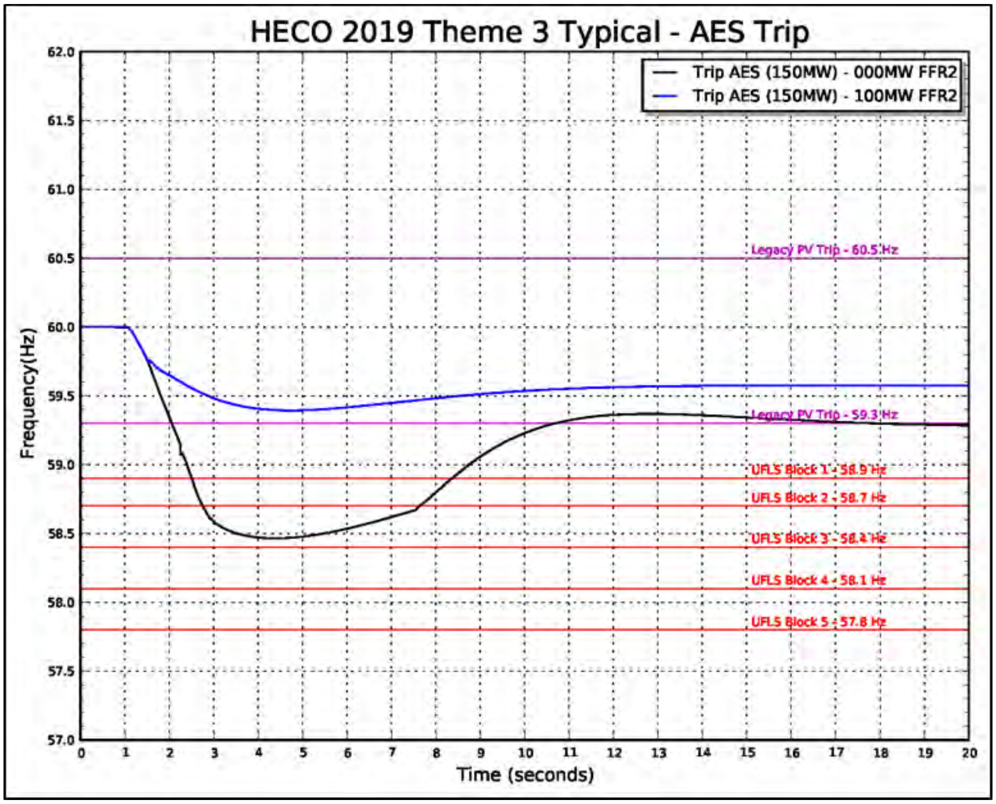


Figure O-17. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-17 shows the frequency response profile for an AES turbine trip dispatched at 134 MW while supplying 16 MW of auxiliary load (150 MW net loss of generation) for a typical hour. System kinetic energy is 4070 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 49 MW. With no FFR2, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

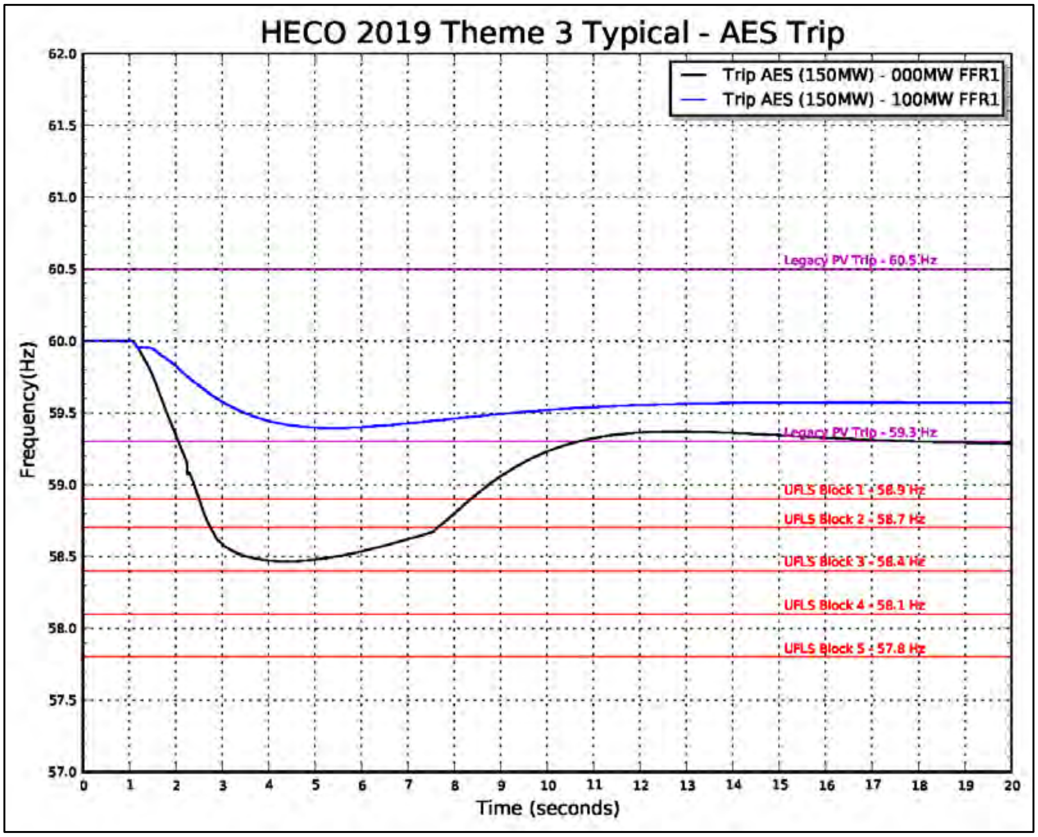


Figure O-18. Frequency Response Profile FFR1Sensitivity Typical Hour

Figure O-18 shows the frequency response profile for this analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

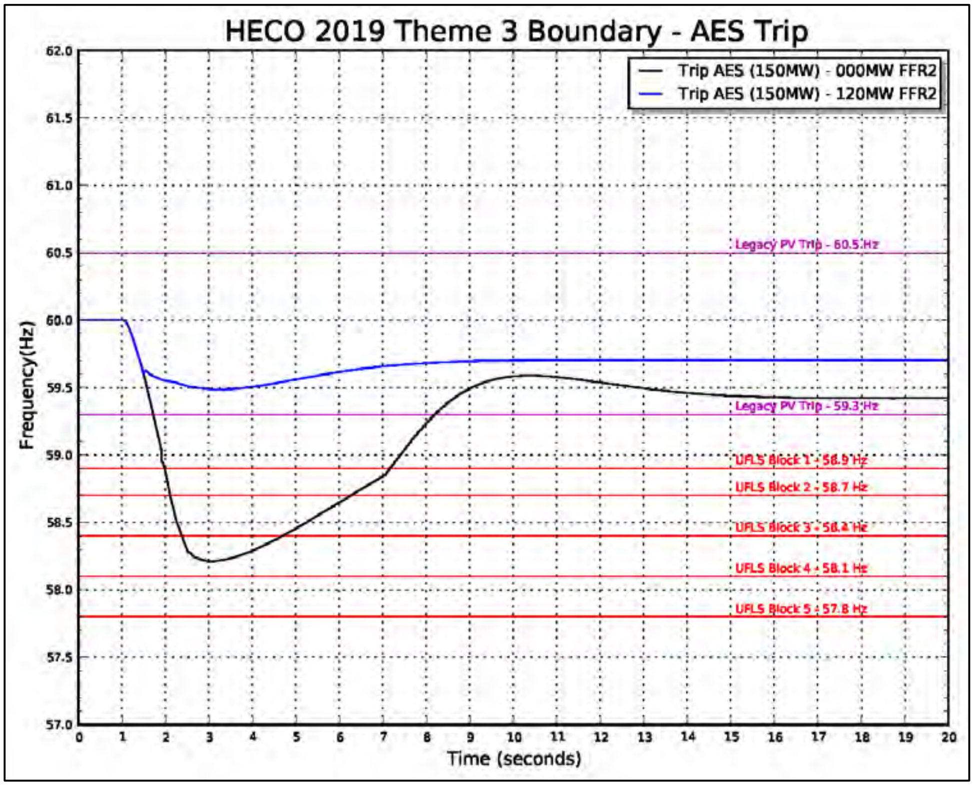


Figure O-19. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-19 shows the frequency response profile for an AES turbine trip dispatched at 134 MW while supplying 16 MW of auxiliary load (150 MW net loss of generation) for a typical hour. System kinetic energy is 2457 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 41 MW. With no FFR2, the frequency nadir reaches 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

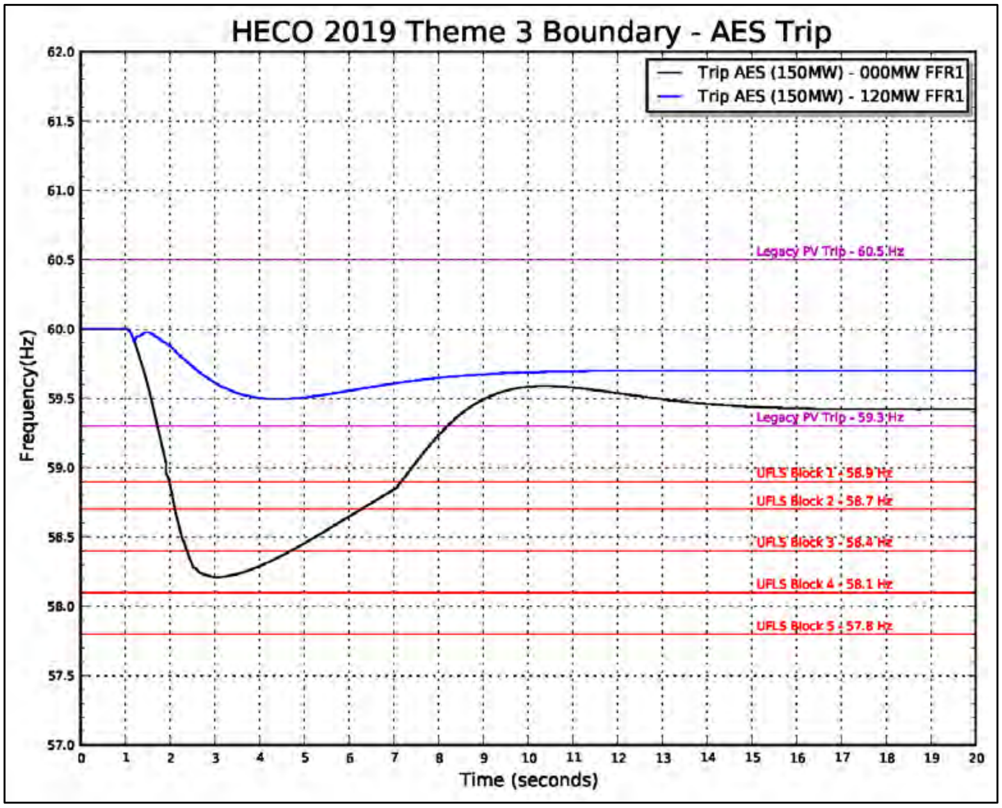


Figure O-20. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-20 shows the frequency response profile for this analysis. The capacity of FFR1required to bring the system into compliance with TPL-001 is 120 MW.

138 kV Fault Analysis

Simulations were performed for 39 transmission system breakers. A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2019 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	No Plot
AES-CEIP 2	AES	323	15	AES Gen	Stable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Unstable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Unstable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Unstable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Unstable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Unstable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Unstable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Unstable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Unstable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Unstable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Unstable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Unstable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Unstable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Unstable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Unstable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Unstable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Unstable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Unstable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Unstable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Unstable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Unstable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-13. Summary of Results for the 2019 Breaker Failure Analysis

Table O-13 shows the results of the breaker failure analysis. For the typical hour, 16 simulations resulted in unstable operation. For the boundary hour, 36 simulations resulted in unstable operation. One simulation for the boundary hour could not be solved.

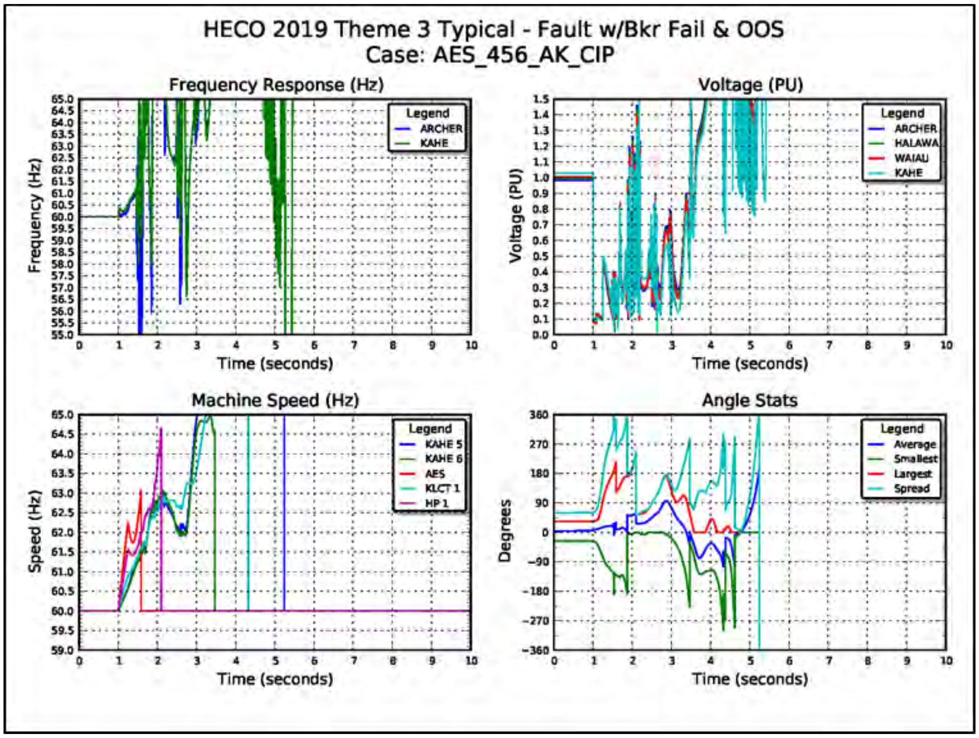


Figure O-21. System Performance for BKR 456 Failure Analysis

Figure O-21 shows four plots that illustrate unstable operation for a fault on the AES-Kalaeloa line and BKR 456 fails to operate. The Machine Speed plot shows Kahe 5 (blue) and Kalaeloa CT1 (teal) losing synchronism with the system. More analysis is required to determine mitigation alternatives for rotor angle instability.

Theme 1 – Aggressive Renewables

Summary

System security analyses were not performed on a specific resource plan for Theme 1 in the time available. High-level fatal flaw assessments were performed on the Theme 1 2045 plans by applying system security requirements for Themes 2 and 3.

Theme 2 – LNG Plan

2023

System security analysis was performed on two hours that were selected from the Theme 2 production cost simulations that represents a typical hour and a boundary condition.

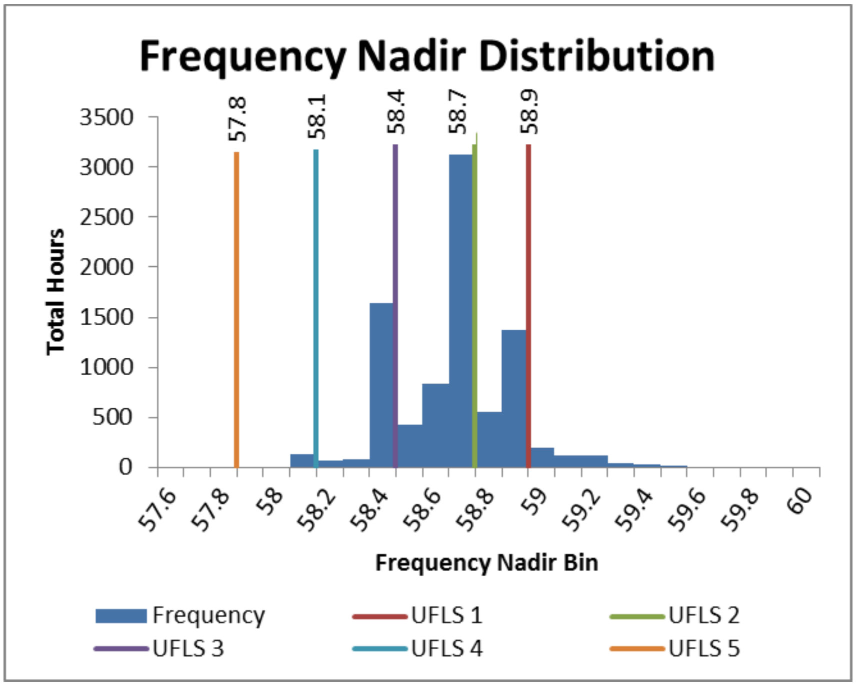


Figure O-22. Frequency Nadir Histogram for 2023

Figure O-22 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1636 hours was 3:00 PM on Tuesday, August 22. The frequency nadir range for the typical hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 129 hours was 5:00 AM on Sunday, September 3. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires four blocks of UFLS to stabilize system frequency.

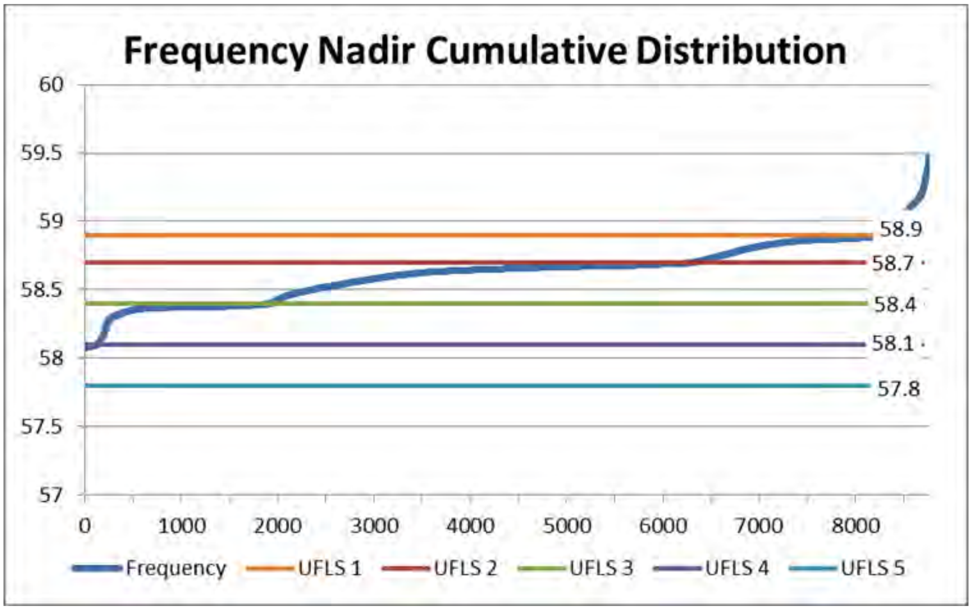


Figure O-23. Frequency Nadir Duration Curve for 2023

Figure O-23 shows the frequency nadir duration curve for 2023.

Unit Commitment Order	Unit Ratings							Theme 2 - HECO 2023 (Typical) Tue 8/22/23 Hour 15			Theme 2 - HECO 2023 (Boundary) Sun 9/3/23 Hour 5		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	45.0	1.0	20.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	21.0	1.5	11.0			
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	80.0	4.0	51.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	10.0	30.0	0.0	38.0	2.0	28.0
GE-CT1	77.0	42.0			3.40	98.5	335	72.0	5.0	30.0	77.0	0.0	35.0
GE-CT2	77.0	42.0			3.40	98.5	335				77.0	0.0	35.0
GE-CT3	77.0	42.0			3.40	98.5	335				77.0	0.0	35.0
GE-ST1	152.0	22.0			7.60	200.0	1520	22.0	130.0	0.0	152.0	0.0	130.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 6	133.8	63.9			4.36	158.8	692						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 1	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 2	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 3	0.0	0.0			1.71	101.0	173	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	153	0						37			19		
-Kahuku	30	0						4			4		
-Kawailoa	69	0						16			6		
-Na Pua Makani	24	0						14			0		
-Future Wind	30	0						3			9		
DG-PV	807	0						489			0		
Station PV	783	0						449			0		
Total Kinetic Energy									3334			4452	
Total Load									1225			643	
Total Thermal Generation									250			624	
Total Renewable Generation									975			19	
Total Generation									1225			643	
Excess Generation									0			0	
Total Up Regulation									172			13	
Total Down Regulation									112			383	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		44.7	59.3Hz Output		0.0
	60.5Hz Capacity			105.7				60.5Hz Output		64.0	60.5Hz Output		0.0

Table O-14. Commitment and Dispatch 2023

Table O-14 shows the unit commitment and dispatch for the typical hour (8/22/2023, 3:00 PM) and boundary hour (9/3/2023, 5:00 AM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

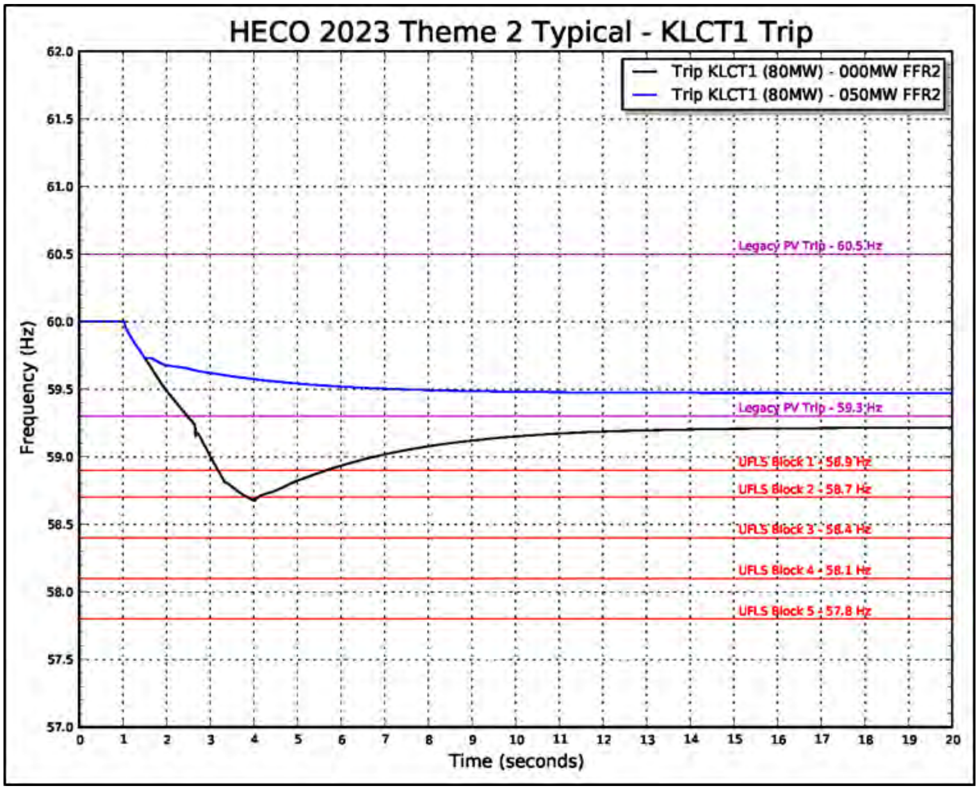


Figure O-24. Frequency Response Profile for FFR2 Typical Hour

Figure O-24 shows the frequency response profile for a Kalaeloa CT1 trip, the largest contingency at that time, at 80 MW for a typical hour. System kinetic energy is 3334 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 45 MW. With no FFR2, the frequency nadir reaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 50 MW.

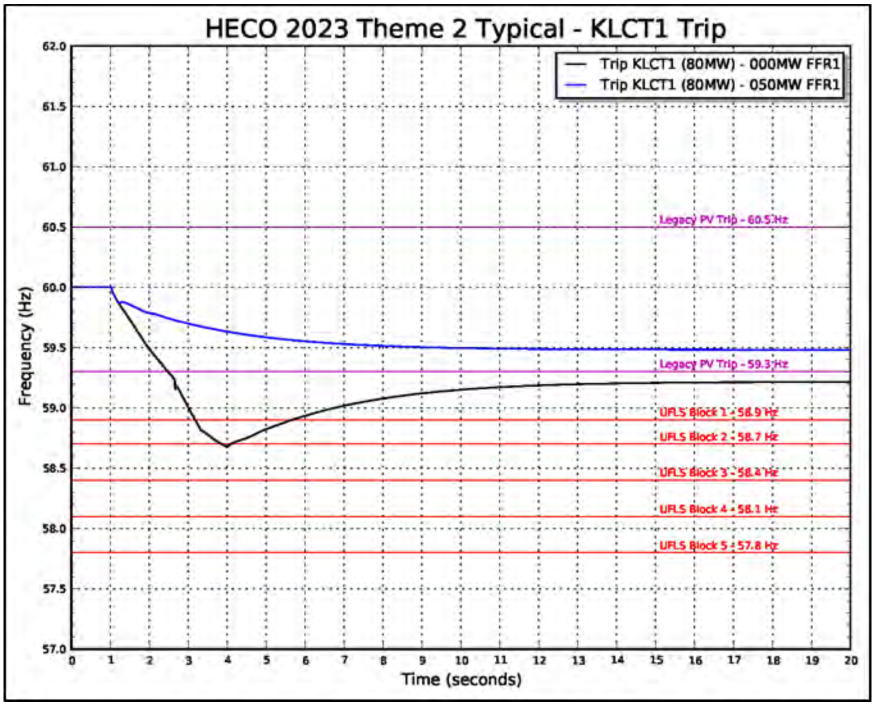


Figure O-25. Frequency Response Profile for FFR1 Typical Hour

Figure O-25 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 50 MW.

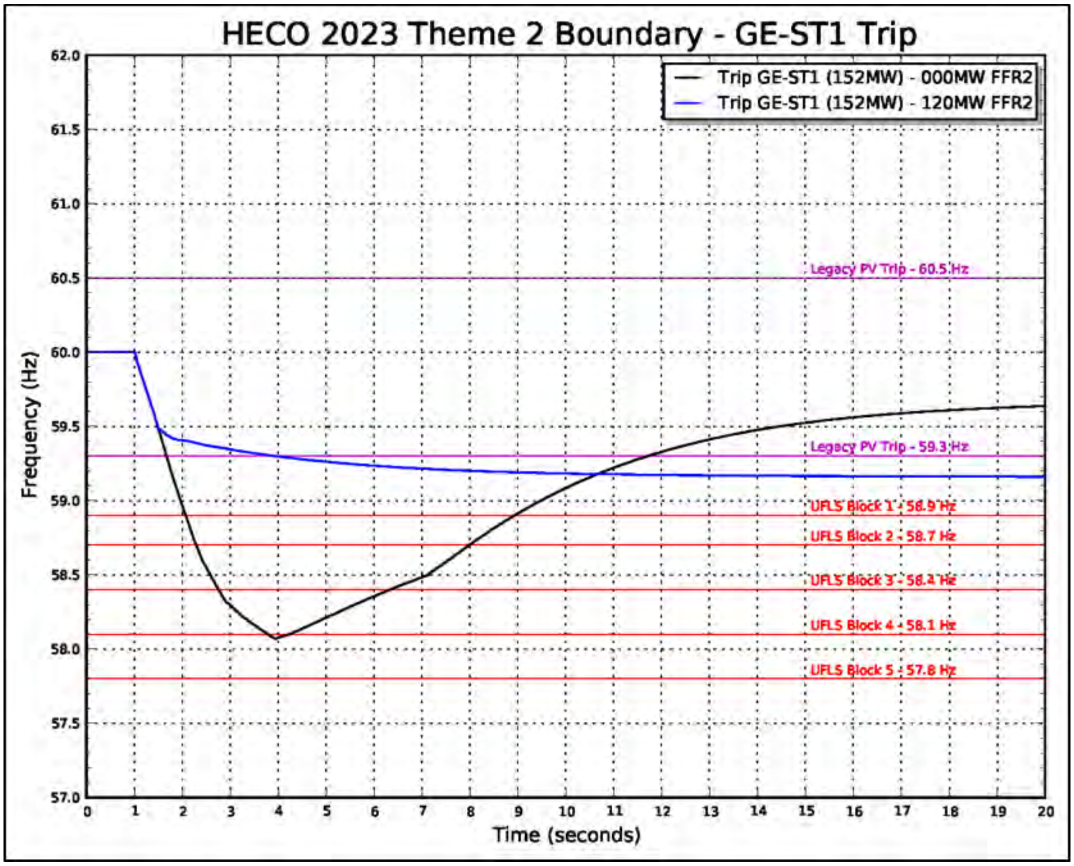


Figure O-26. Frequency Response Profile for FFR2 Boundary Hour

Figure O-26 shows the frequency response profile for a GE single train combined cycle (STCC) trip at 120 MW for a boundary hour. System kinetic energy is 4452 MW-sec. With no FFR2, the frequency nadir breaches 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

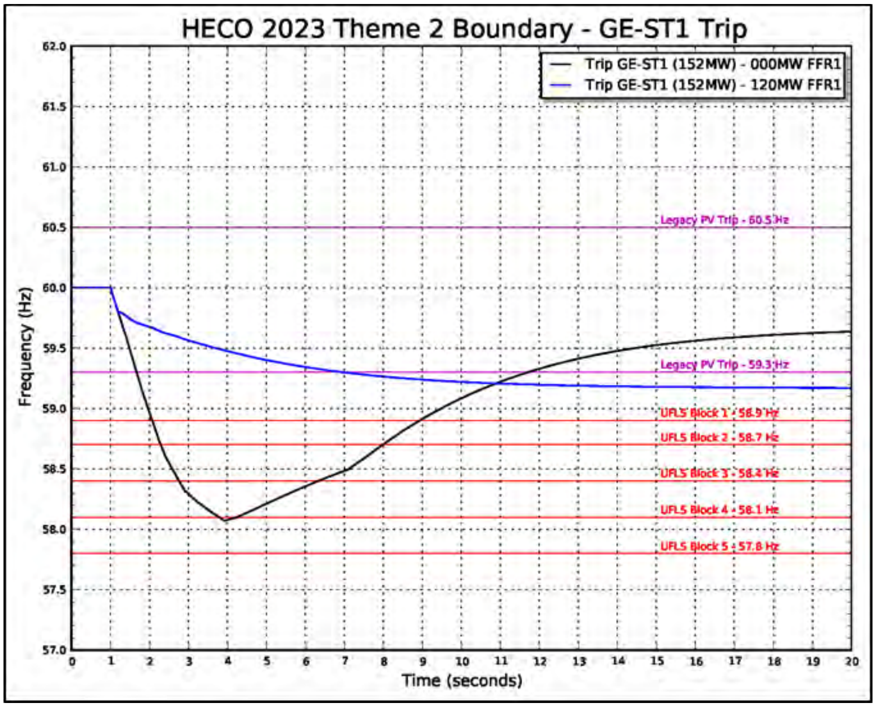


Figure O-27. Frequency Response Profile for FFR1 Boundary Hour

Figure O-27 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

138 kV Fault Analysis

Simulations were performed for 39 transmission system breakers. A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2023 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Stable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Stable
AES-CEIP 2	AES	323	15	AES Gen	Stable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Unstable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Unstable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Unstable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Unstable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Unstable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Unstable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Unstable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Unstable	Stable

Table O-15. Summary of Results for the 2023 Breaker Failure Analysis

Table O-15 shows the results of the breaker failure analysis. For the typical hour, 19 simulations resulted in unstable operation. For the boundary hour, 11 simulations resulted in unstable operation. System inertia for the boundary hour is higher than the typical hour that could impact rotor angle stability. Further analyses will be performed to determine mitigation alternatives.

2030

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

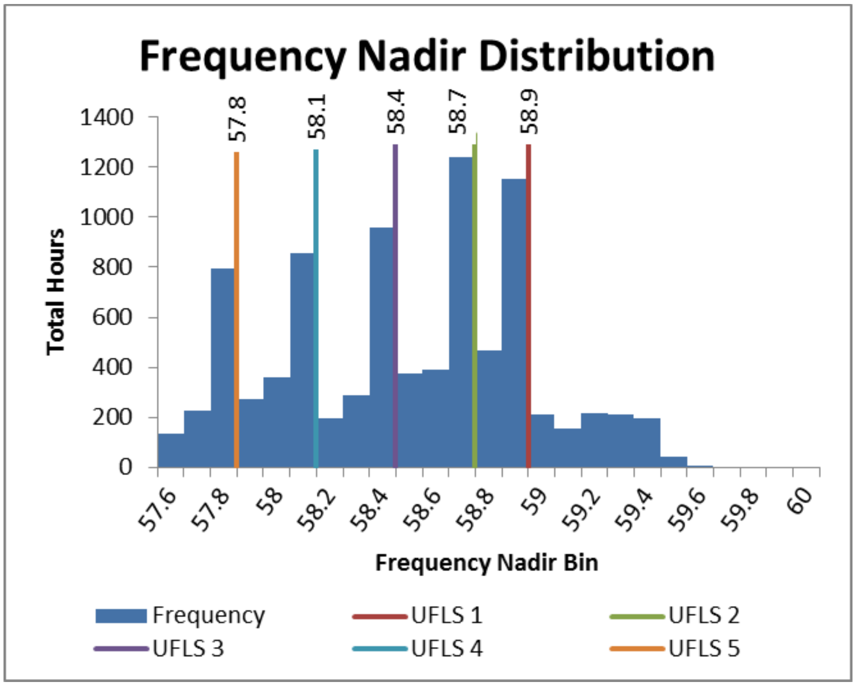


Figure O-28. Frequency Nadir Histogram for 2030

Figure O-28 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 797 hours was 1:00 PM on Friday, April 5. The frequency nadir range for the typical hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

The boundary hour selected from the minimum distribution of 133 hours was 3:00 AM on Sunday, May 17. The frequency nadir range for the boundary hour is 57.5 – 57.6 Hz that requires five blocks of UFLS to stabilize system frequency.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

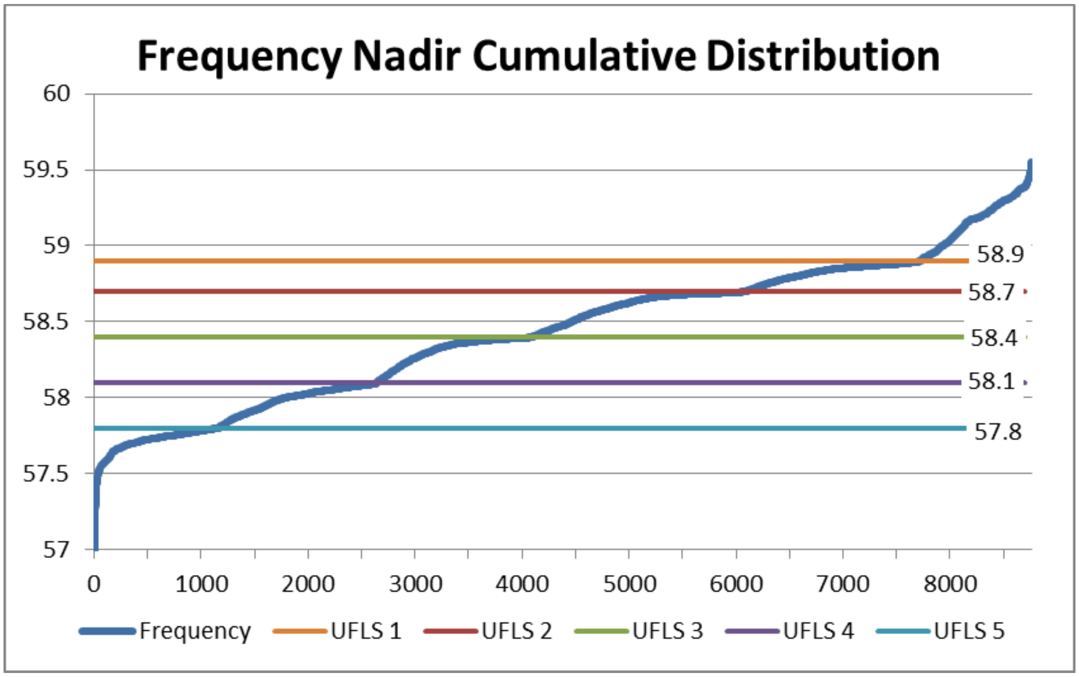


Figure O-29. Frequency Nadir Duration Curve for 2030

Figure O-29 shows the frequency nadir duration curve for 2030.

Unit Commitment Order	Unit Ratings							Theme 2 - HECO 2030 (Typical) Fri 4/5/30 Hour 13			Theme 2 - HECO 2030 (Boundary) Sun 3/17/30 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	36.0	10.0	11.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
GE-CT1	70.0	36.0			3.40	98.5	335				42.0	28.0	6.0
GE-CT2	75.0	41.0			3.40	98.5	335						
GE-CT3	76.0	41.0			3.40	98.5	335						
GE-ST1	162.0	28.0			7.60	200.0	1520						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 6	133.8	63.9			4.36	158.8	692						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 9	52.9	5.9			7.84	57.0	447						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 3	0.0	0.0			1.71	101.0	173	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 2	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 1	0.0	0.0			2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	553	0						202			433		
-Kahuku	30	0						21			13		
-Kawailoa	69	0						21			14		
-Na Pua Makani	24	0						21			21		
-Future Wind	30	0						6			6		
-Offshore Wind	400	0						133			379		
DG-PV	1354	0						715			0		
Station PV	783	0						218			0		
Total Kinetic Energy									1168			1359	
Total Load									1203			511	
Total Thermal Generation									69			78	
Total Renewable Generation									1135			433	
Total Generation									1203			511	
Excess Generation									0			0	
Total Up Regulation									0			38	
Total Down Regulation									34			17	
Legacy DG-PV	59.3Hz Capacity			73.8				59.3Hz Output		39.0	59.3Hz Output		0.0
	60.5Hz Capacity			105.7				60.5Hz Output		55.8	60.5Hz Output		0.0

Table O-16. Unit Commitment and Dispatch 2030

Table O-16 shows the unit commitment and dispatch for the typical and boundary hours. Simulations were performed for these system conditions to determine system security requirements.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

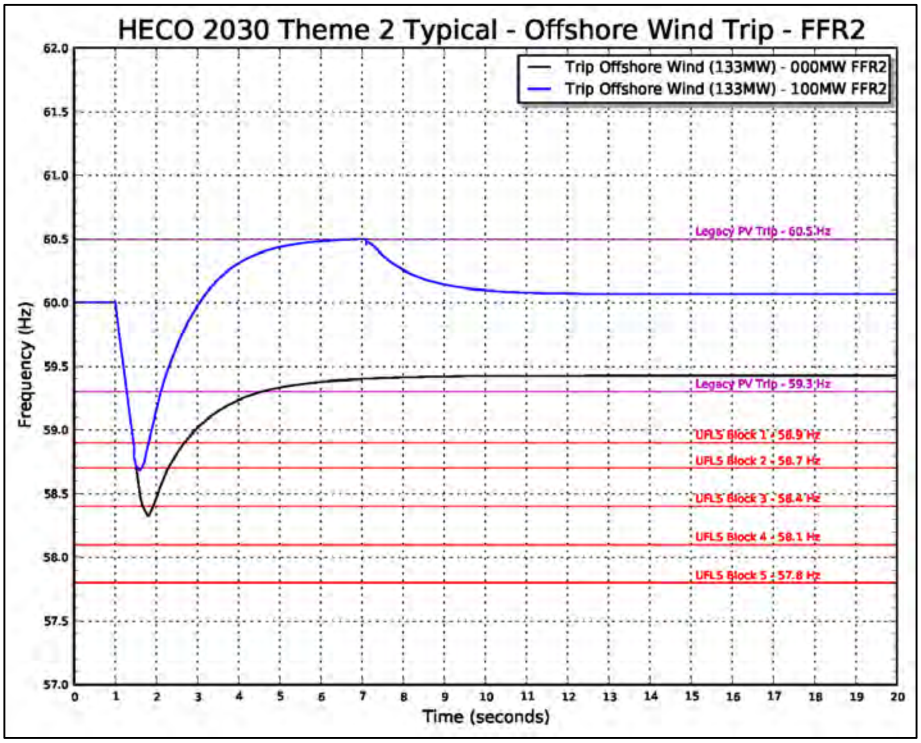


Figure O-30. Frequency Response Profile for FFR2 Typical Hour

Figure O-30 shows the frequency response profile for a cable trip of an offshore wind turbine carrying 133 MW for a typical hour. System kinetic energy is 1168 MW-sec and the capacity of legacy PV that will disconnect from the system is 39 MW. With no FFR2, the frequency nadir breaches 58.4 Hz requiring 3 blocks of UFLS to stabilize system frequency. Simulations of 100 MW of FFR2 in conjunction with the 2 blocks of UFLS over compensates for this contingency, causing system frequency to exceed 60.5 Hz. The 30-cycle time delay is too long to dispatch FFR2, indicating that there is no amount of FFR2 that will bring the system into compliance with TPL-001.

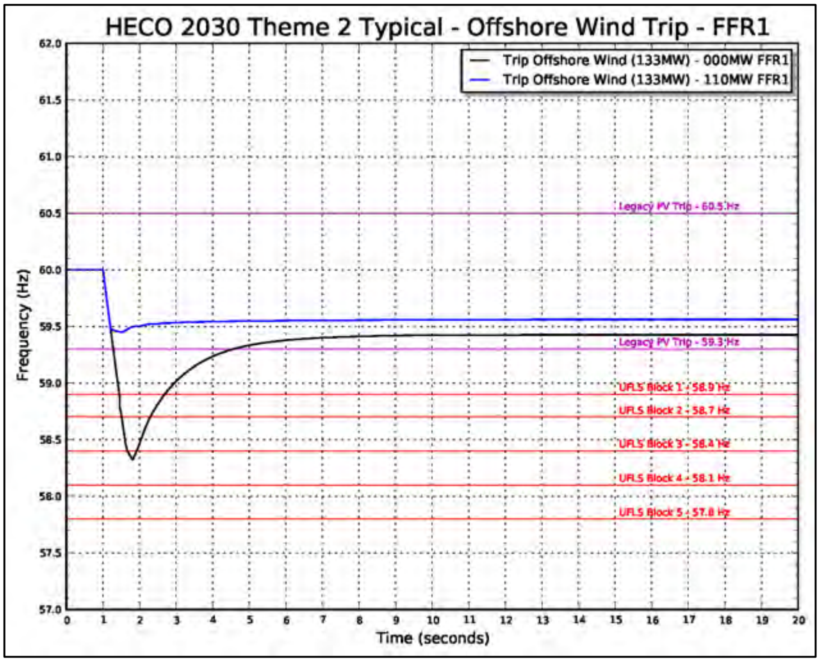


Figure O-31. Frequency Response Profile for FFR1 Typical Hour

Figure O-31 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW.

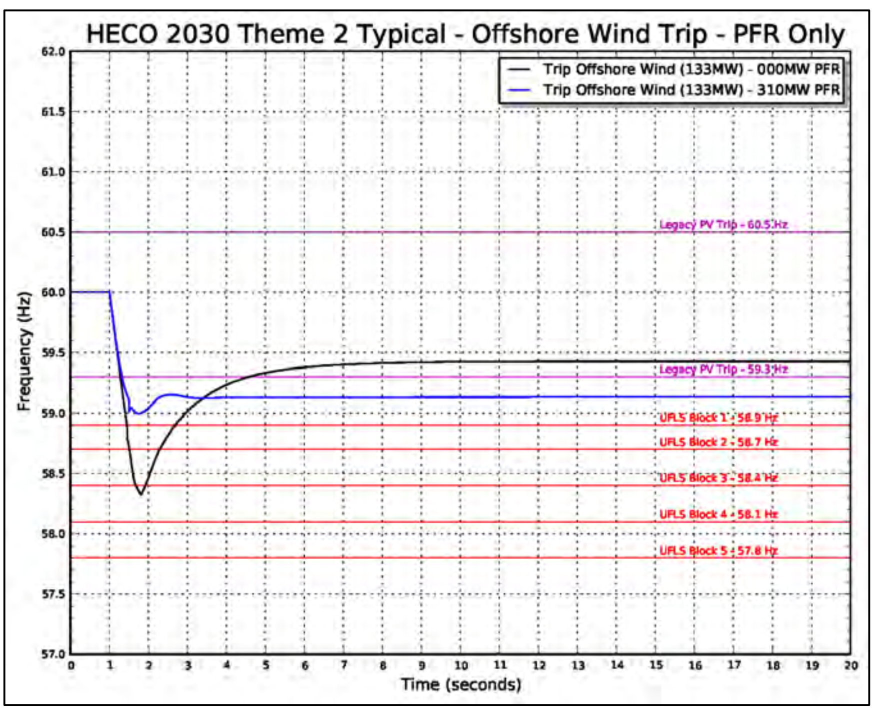


Figure O-32. Frequency Response Profile for PFR Typical Hour

Figure O-32 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 310 MW.

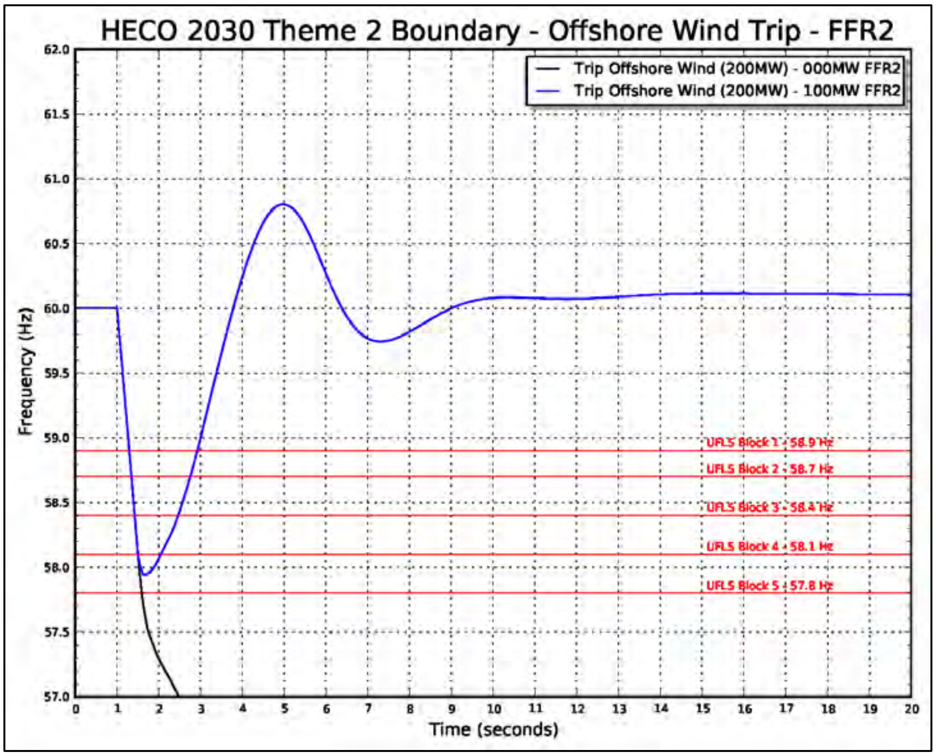


Figure O-33. Frequency Response Profile for FFR2 Boundary Hour

Figure O-33 shows the frequency response profile for a cable trip of an offshore wind turbine carrying 200 MW for a boundary hour. System kinetic energy is 1359 MW-sec. With 100 MW of FFR2, the frequency nadir breaches 58.0 Hz that initiates 4 blocks of UFLS. The 100 MW of FFR2 in conjunction with the 4 blocks of UFLS over compensates for this contingency and causes system frequency to exceed 60.5 Hz. Therefore, there is no amount of FFR2 that will bring the system into compliance with TPL-001.

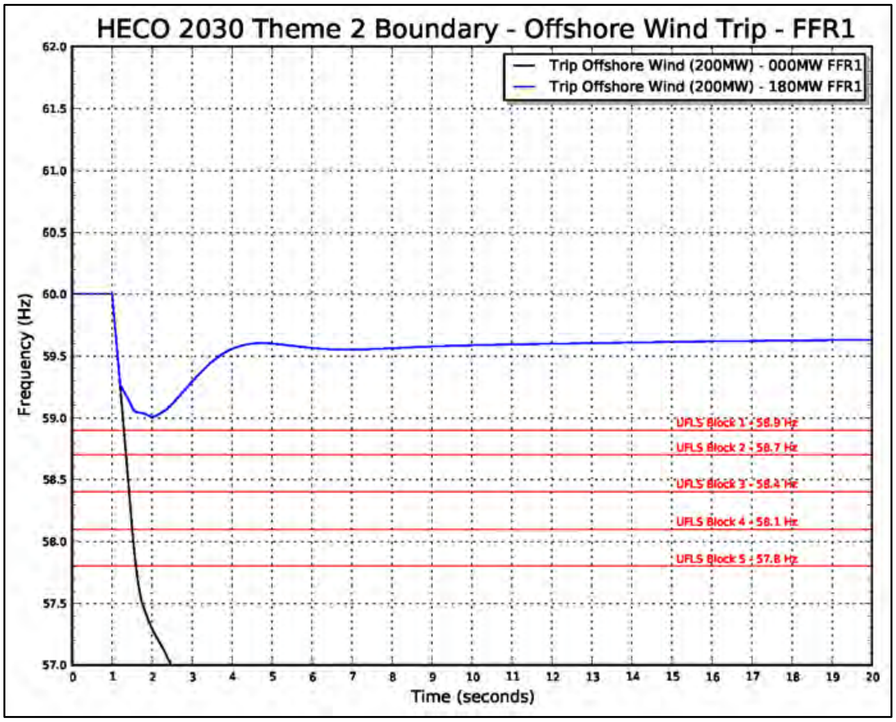


Figure O-34. Frequency Response Profile for FFR1 Boundary Hour

Figure O-34 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 180 MW.

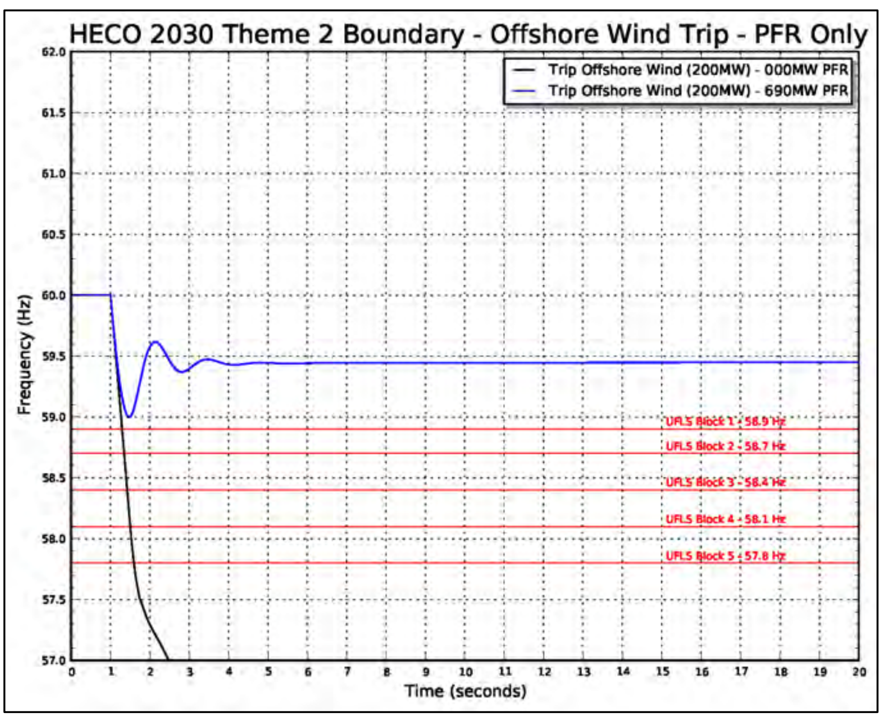


Figure O-35. Frequency Response Profile for PFR Boundary Hour

Figure O-35 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 690 MW.

138 kV Fault Analysis

Simulations were performed for electrical faults on the 138 kV transmission system busses. A three-phase fault was placed on 39 busses to evaluate system performance to normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any significant system security issues.

2030 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Stable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Stable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Stable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Unstable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Unstable	Unstable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Unstable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Unstable	Unstable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Unstable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Unstable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Unstable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-17. Summary of Results for the 2030 Breaker Failure Analysis

Table O-17 shows the results of the breaker failure analysis. For the typical hour, 21 simulations resulted in unstable operation. For the boundary hour, 12 simulations resulted in unstable operation. System inertia for the boundary hour is higher than the typical hour that could impact rotor angle stability.

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition. An additional screening metric was applied to select hours when the output from offshore wind was high to simulate the trip of a 200 MW cable.

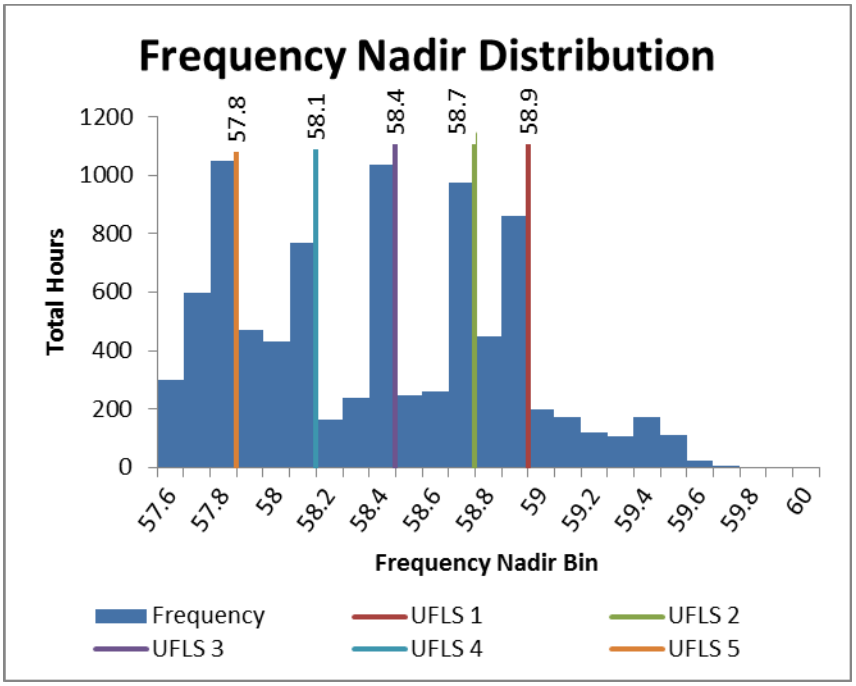


Figure O-36. Frequency Nadir Histogram for 2045

Figure O-36 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1049 hours was 2:00 PM on Thursday, July 6. The frequency nadir range for the typical hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

The boundary hour selected from the minimum distribution of 298 hours was 4:00 PM on Sunday, May 15. The frequency nadir range for the boundary hour is 57.5 – 57.6 Hz that requires five blocks of UFLS to stabilize system frequency.

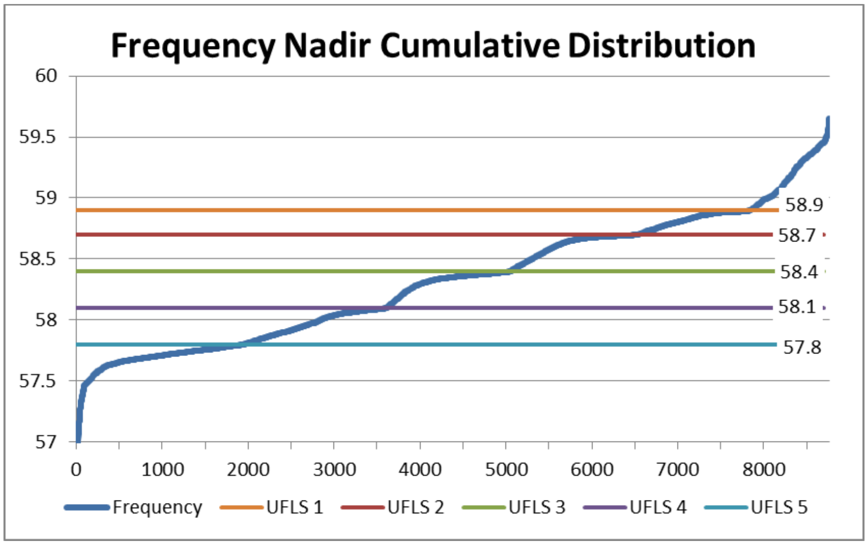


Figure O-37. Frequency Nadir distribution Curve for 2030

Figure O-37 shows the frequency nadir duration curve for 2030.

Unit Commitment Order	Unit Ratings							Theme 2 - HECO 2045 (Typical) Thu 7/6/45 Hour 14			Theme 2 - HECO 2045 (Boundary) Sun 5/14/45 Hour 16		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	41.0	5.0	16.0
HPOWER-2	22.5	10.0			3.41	42.1	144				21.0	1.5	11.0
GE-CT1	70.0	36.0			3.40	98.5	335						
GE-CT2	75.0	41.0			3.40	98.5	335						
GE-CT3	76.0	41.0			3.40	98.5	335						
GE-ST1	162.0	28.0			7.60	200.0	1520						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 6	133.8	63.9			4.36	158.8	692						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 3	86.2	23.7	25.0	5.0	1.71	101.0	173	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 2	82.2	23.8	25.0	5.0	2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 1	82.2	23.8	25.0	5.0	2.05	96.0	197	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	953	0						320			247		
-Kahuku	30	0						14			8		
-Kawailoa	69	0						23			19		
-Na Pua Makani	24	0						21			16		
-Future Wind	30	0						0			0		
-Offshore Wind	800	0						262			204		
DG-PV	2518	0						1077			723		
Station PV	3603	0						128			81		
Total Kinetic Energy									1024			1168	
Total Load									1571			1113	
Total Thermal Generation									46			62	
Total Renewable Generation									1525			1051	
Total Generation									1571			1113	
Excess Generation									0			0	
Total Up Regulation									0			7	
Total Down Regulation									21			27	
Legacy DG-PV	59.3Hz Capacity			0.0				59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-18. Unit Commitment and Dispatch 2045

Table O-18 shows the unit commitment and dispatch for the typical and boundary hours. Simulations were performed for these system conditions to determine system security requirements.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

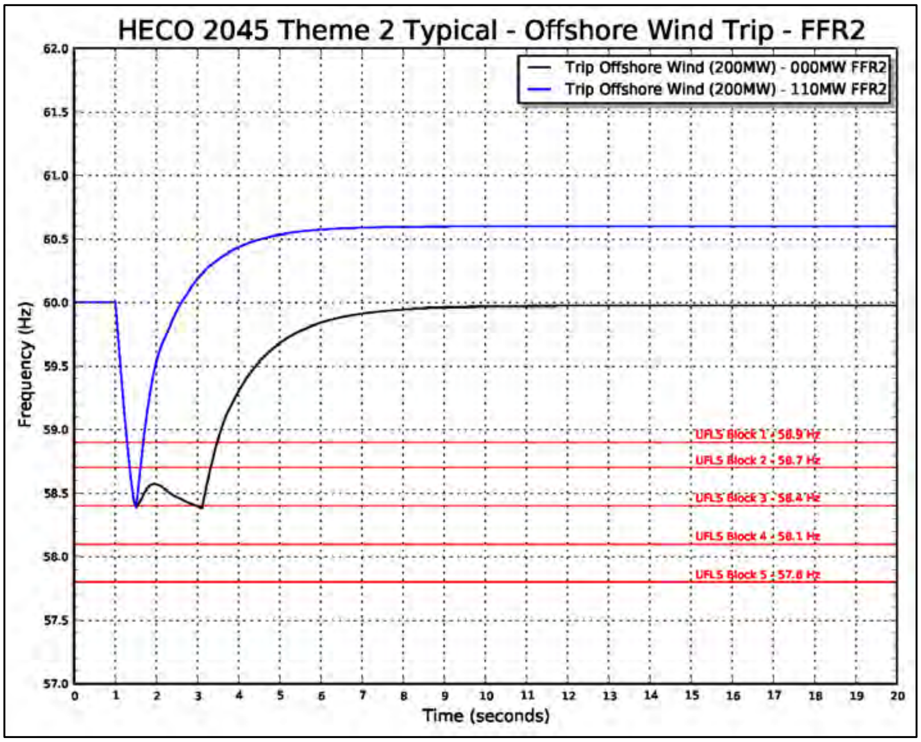


Figure O-38. Frequency Response Profile for FFR2 Typical Hour

Figure O-38 shows the frequency response profile for a 200 MW cable trip from an offshore wind facility. System kinetic energy is 1024 MW-sec. With 110 MW of FFR2, the frequency nadir hits 58.4 Hz requiring 3 blocks of UFLS to stabilize system frequency. Simulations of 110 MW of FFR2 in conjunction with the 3 blocks of UFLS over compensates for this contingency, causes system frequency to exceed 60.5 Hz. The 30-cycle time delay is too long to dispatch FFR2, indicating that there is no amount of FFR2 that will bring the system into compliance with TPL-001.

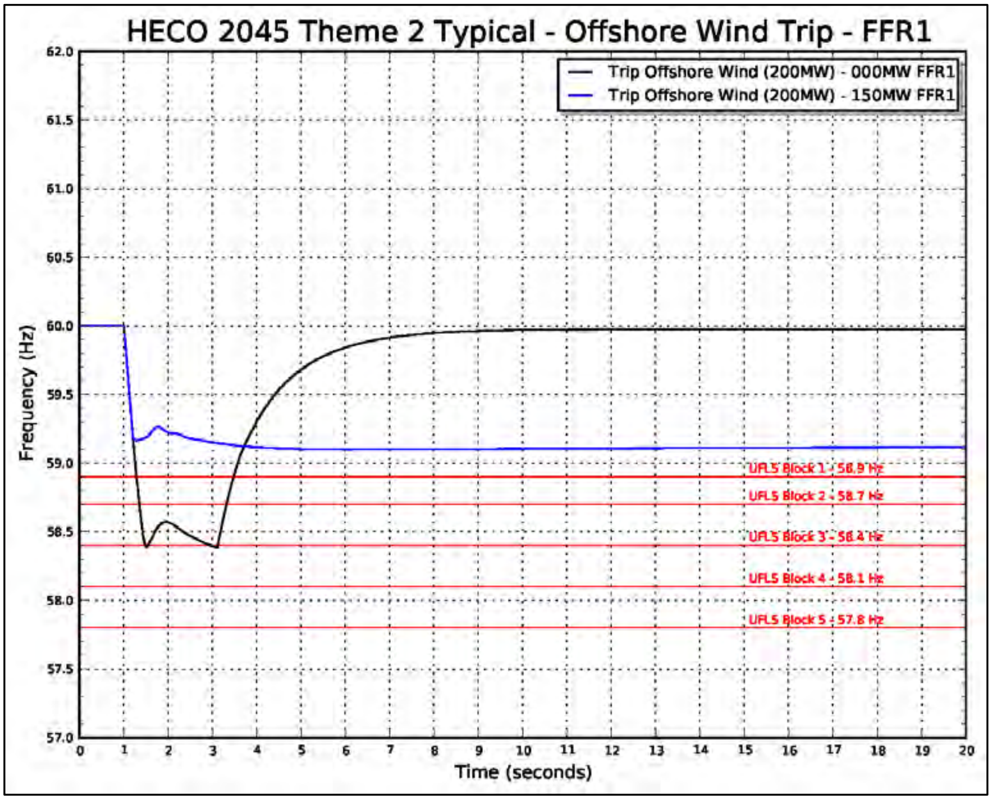


Figure O-39. Frequency Response Profile for FFR1 Typical Hour

Figure O-39 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

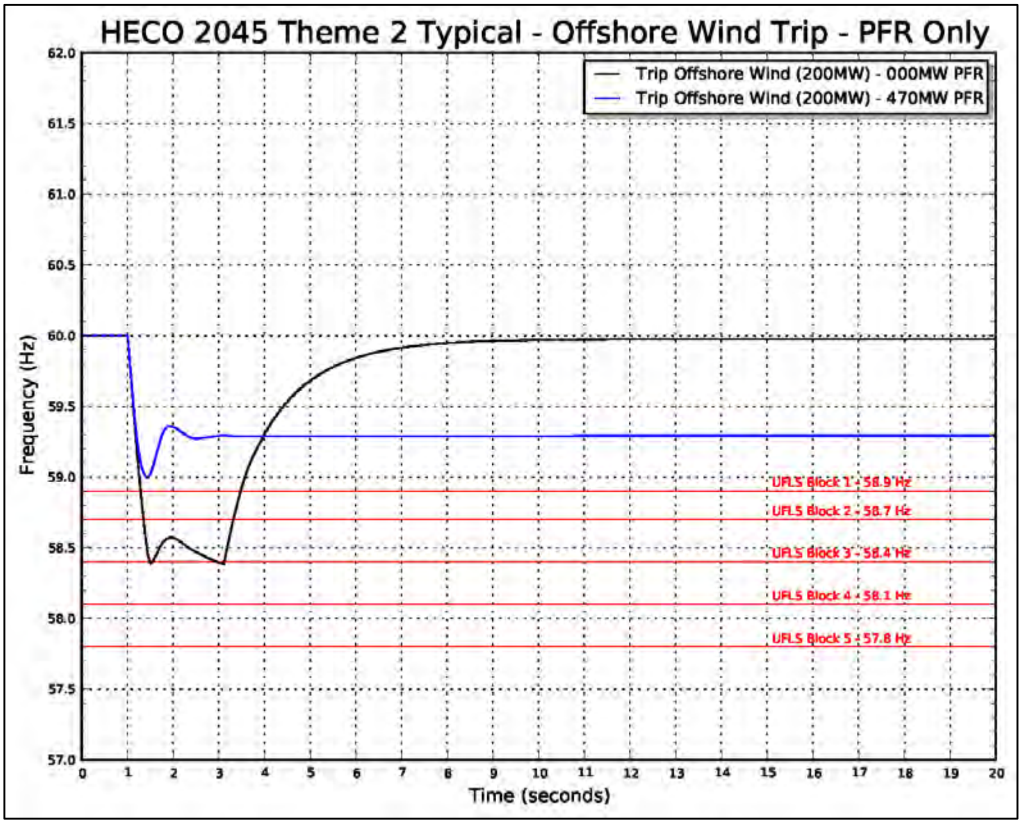


Figure O-40. Frequency Response Profile for PFR Typical Hour

Figure O-40 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 470 MW.

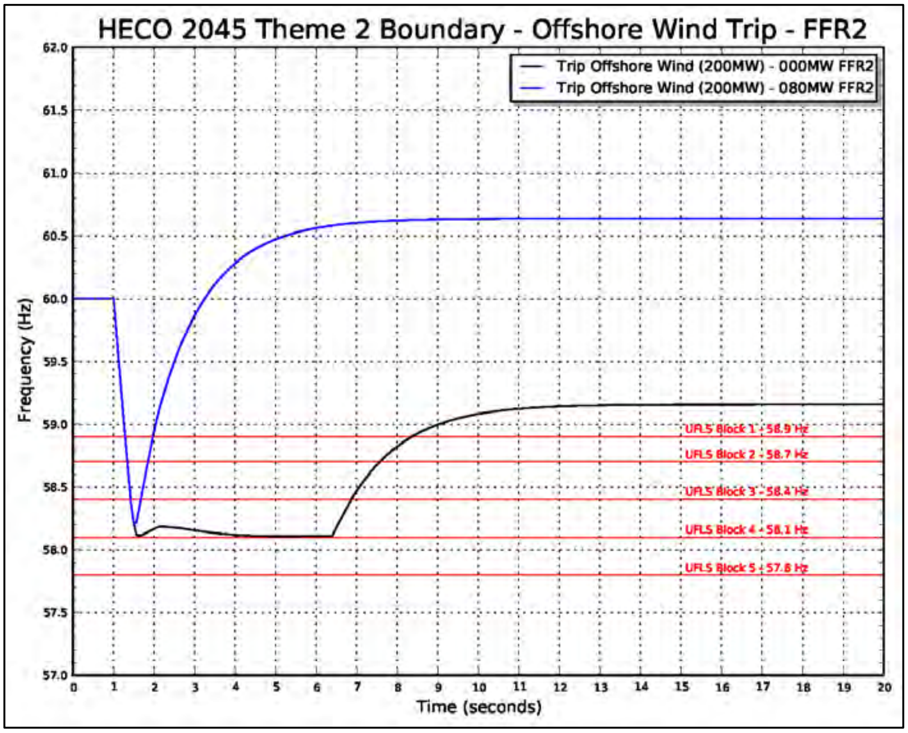


Figure O-41. Frequency Response Profile for FFR2 Boundary Hour

Figure O-41 shows the frequency response profile for a 200 MW cable trip from an offshore wind facility. With 80 MW of FFR2, the frequency nadir hits 59.3 Hz that initiates 2 blocks of UFLS that over compensates for this contingency, causes system frequency to exceed 60.5 Hz. Therefore, there is no amount of FFR2 that will bring the system into compliance with TPL-001.

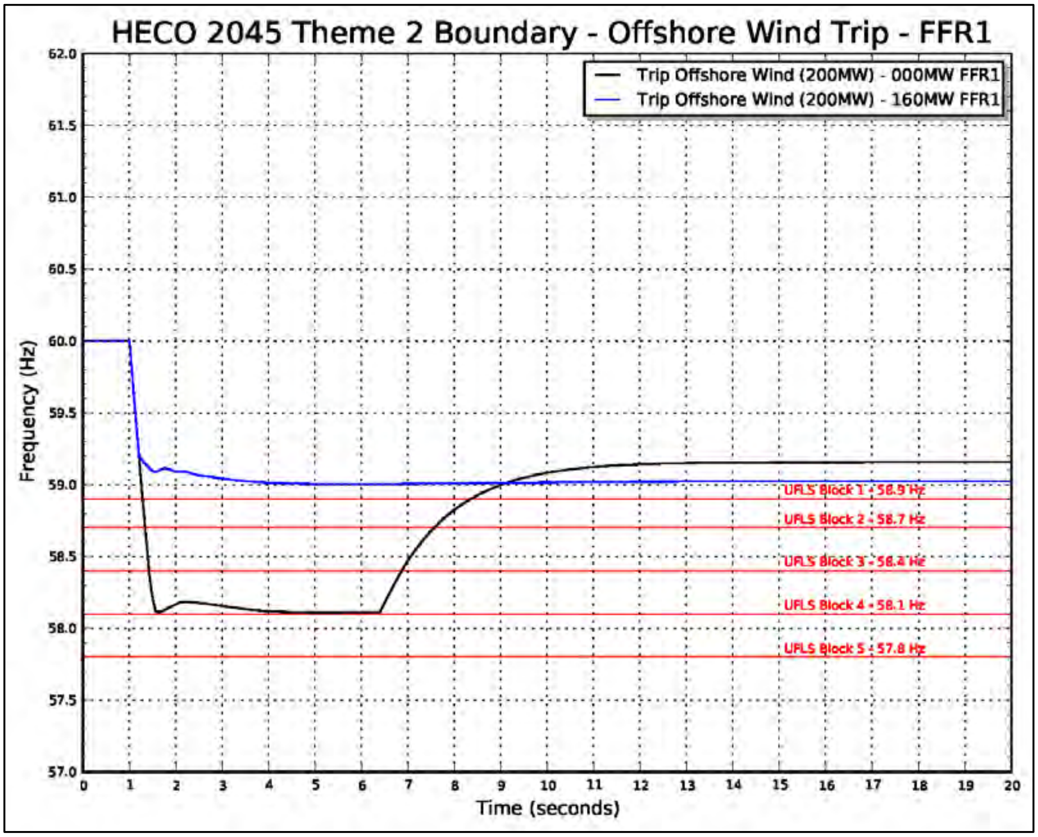


Figure O-42. Frequency Response Profile for FFR1 Boundary Hour

Figure O-42 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 160 MW.

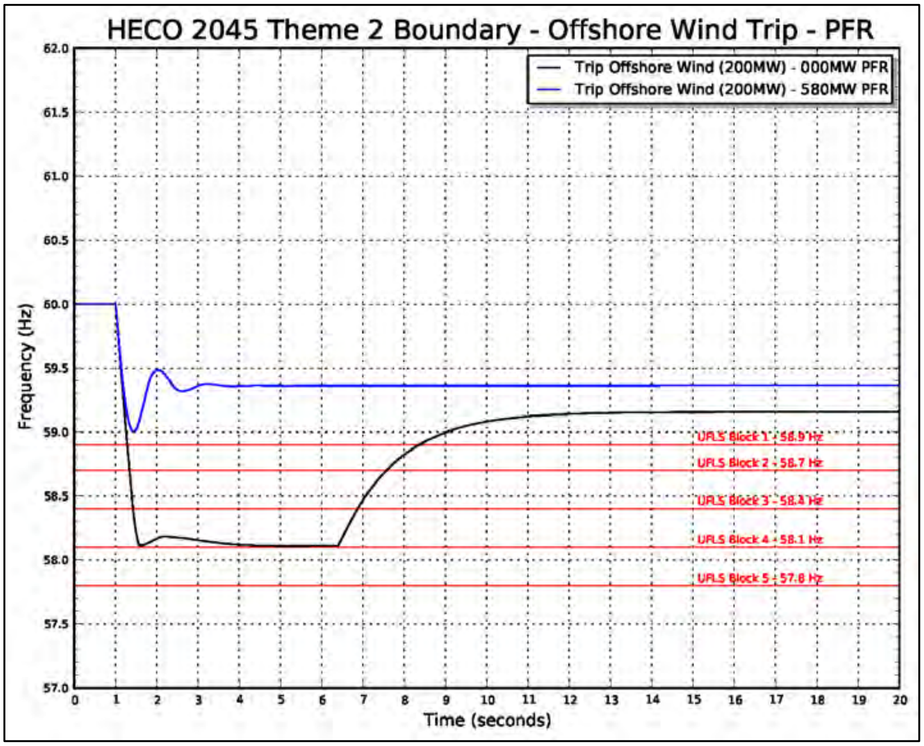


Figure O-43. Frequency Response Profile for PFR Boundary Hour

Figure O-43 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 580 MW.

138 kV Fault Analysis

Simulations were performed for electrical faults on the 138 kV transmission system busses. A three-phase fault was placed on 28 busses to evaluate system performance to normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. Simulations for the normally cleared faults did not produce any system security issues.

2045 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Unstable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Unstable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Unstable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Unstable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-19. Summary of Results for the 2045 Breaker Failure Analysis

Table O-19 shows the results of the breaker failure analysis. For the boundary hour, 13 simulations resulted in unstable operation.

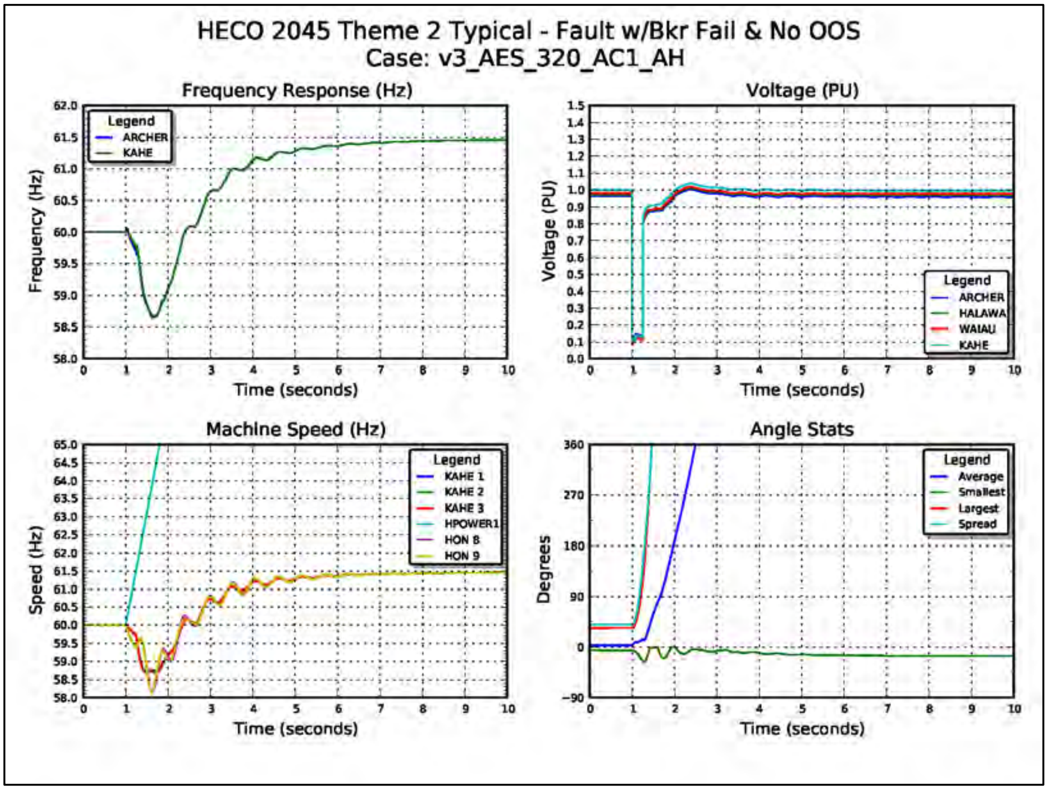


Figure O-44. System Performance for BKR 320 Failure Analysis

Figure O-44 shows four plots that illustrate unstable operation for a fault on the AES-CEIP 1 line and BKR 320 fails to operate. The Machine Speed plot shows HPOWER 1 (teal) losing synchronism with the system. HPOWER 1 has a low inertia constant (2.57 MJ/MVA) that determines the shorter critical clearing time. More analysis is required to determine mitigation alternatives.

Theme 3 – No LNG Unmerged Plan

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition. An additional screening metric was applied to select hours when the output from offshore wind was high to simulate the trip of a 200 MW cable.

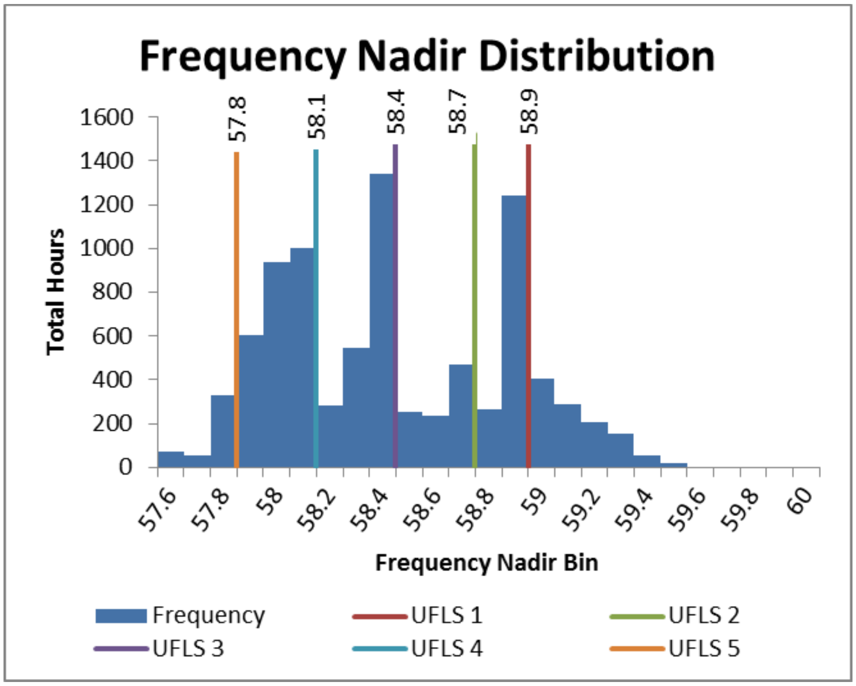


Figure O-45. Frequency Nadir Histogram for 2045

Figure O-45 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1338 hours was 7:00 AM on Monday, November 27. The frequency nadir range for the typical hour was 58.3 – 58.4 Hz that that would require 3 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 71 hours was 3:00 AM on Sunday, March 19. The frequency nadir range for the boundary hour was 57.5 – 57.6 Hz that would require all 5 blocks of UFLS to stabilize system frequency.

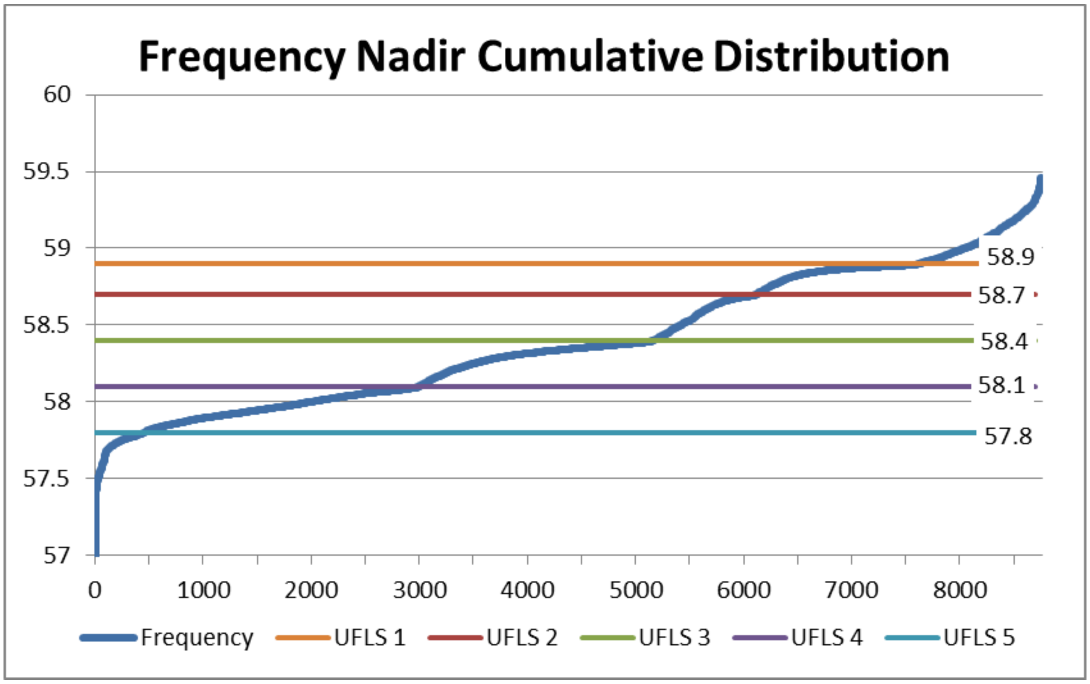


Figure O-46. Frequency Nadir Duration Curve for 2045

Figure O-46 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							Theme 3 - HECO 2045 (Typical) Mon 11/27/45 Hour 7			Theme 3 - HECO 2045 (Boundary) Sun 3/19/45 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	33.0	13.0	8.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144						
JBPHH 1	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 2	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 3	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 4	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 5	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
JBPHH 6	16.8	6.7			0.99	21.8	22	6.7	10.1	0.0			
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	44.4	39.6	15.4			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	21.2	18.8	11.2			
KMCBH 1	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 2	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 3	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 4	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 5	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
KMCBH 6	9.2	4.6			0.99	10.9	11	4.6	4.6	0.0			
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	44.4	39.6	15.4			
Schofield 1	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 2	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 3	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 4	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 5	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Schofield 6	8.0	2.0			0.99	10.9	11	2.0	6.0	0.0			
Kahe 5	134.6	64.7			4.36	158.8	692						
Kahe 3	86.2	23.7	25.0	5.0	1.71	101.0	173						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 2	82.2	23.8	25.0	5.0	2.05	96.0	197						
Kahe 1	82.2	23.8	25.0	5.0	2.05	96.0	197						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
CIP1	112.2	41.2			4.72	162.0	765						
Waiau 10	49.9	5.9			7.84	57.0	447						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 5	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 6	0.0	0.0			1.88	64.0	120	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 6	133.8	63.9			4.36	158.8	692	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			4.51	57.5	259	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			4.51	57.5	259	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	953	0						685			569		
-Kahuku	30	0						3			5		
-Kawailoa	69	0						12			20		
-Na Pua Makani	24	0						21			21		
-Future Wind	30	0						4			8		
-Offshore Wind	800	0						645			515		
DG-PV	2518	0						0			0		
Station PV	3603	0						0			0		
Total Kinetic Energy									3392			1664	
Total Load									908			604	
Total Thermal Generation									223			35	
Total Renewable Generation									685			569	
Total Generation									908			604	
Excess Generation									0			0	
Total Up Regulation									235			11	
Total Down Regulation									50			10	
Legacy DG-PV	59.3Hz Capacity			0.0				59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-20. Unit Commitment and Dispatch 2045

Table O-20 shows the unit commitment and dispatch for the typical and boundary hours. Simulations were performed for these system conditions to determine system security requirements.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

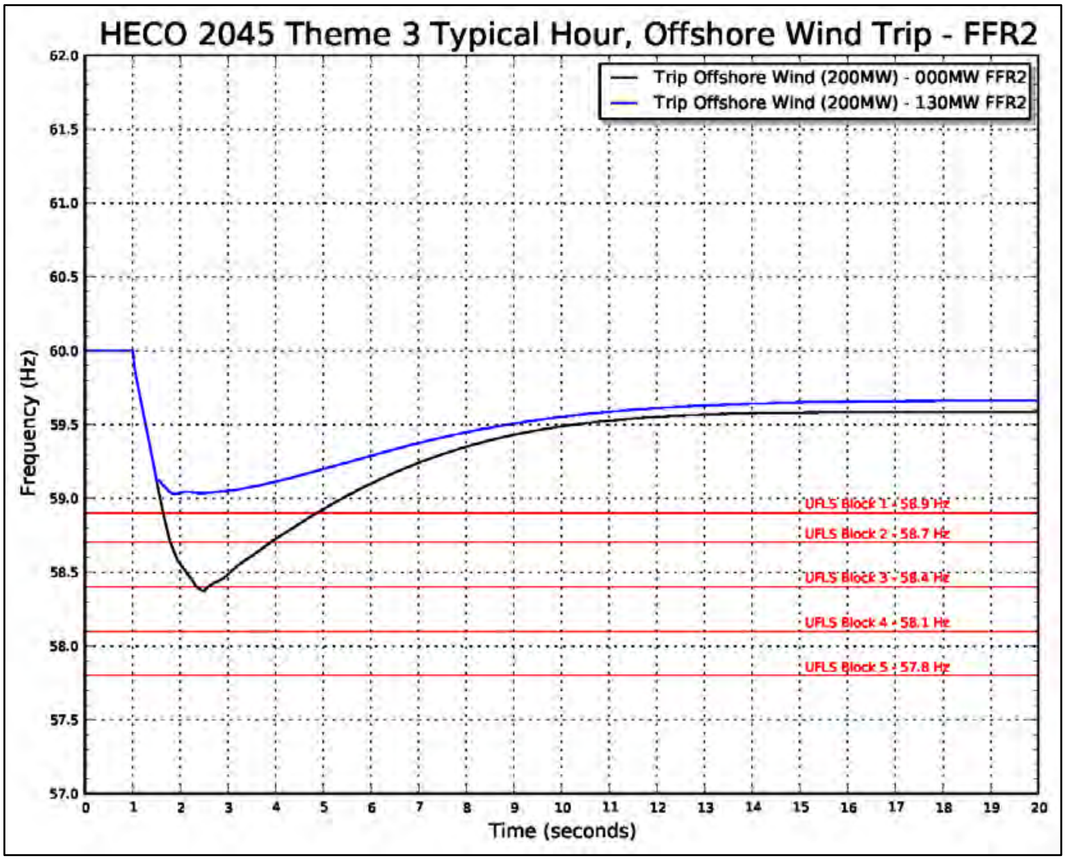


Figure O-47. Frequency Response Profile for FFR2 Typical Hour

Figure O-47 shows the frequency response profile for a 200 MW cable trip of an offshore wind plant for the typical hour. System kinetic energy is 3392 MW-sec. Without FFR2, the frequency nadir breaches 58.4 Hz requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

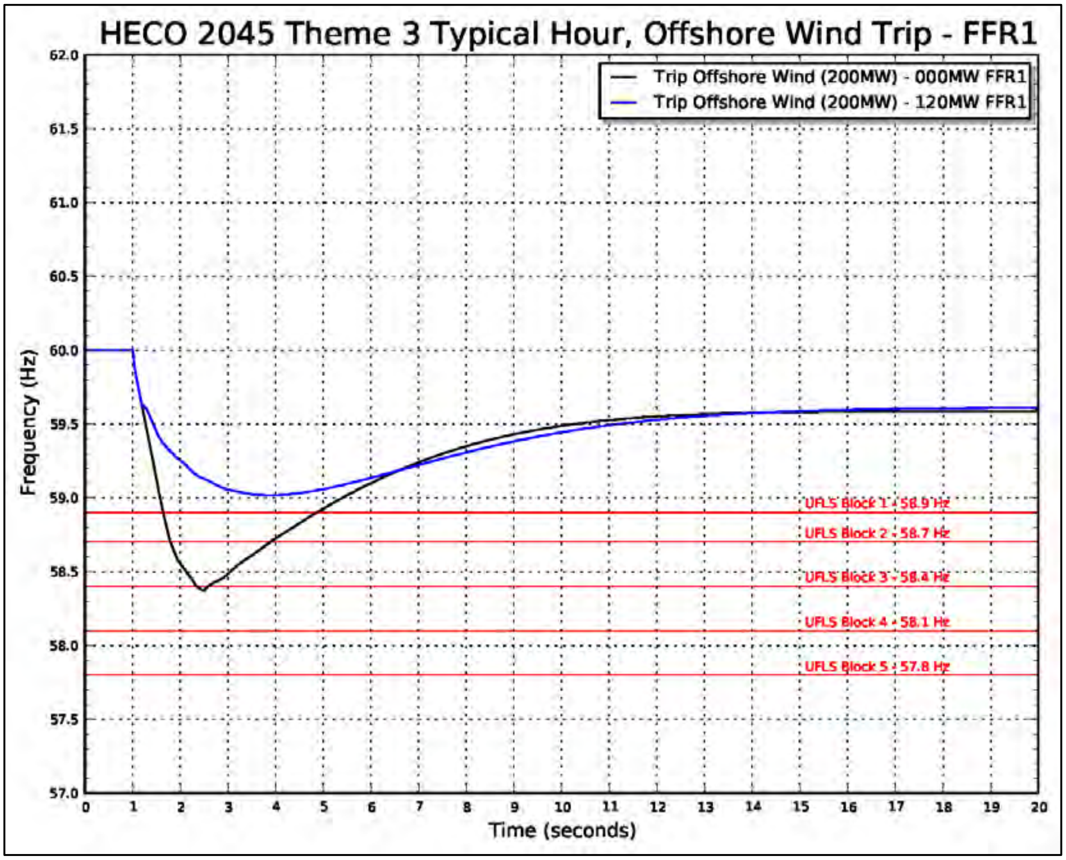


Figure O-48. Frequency Response Profile for FFR1 Typical Hour

Figure O-48 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

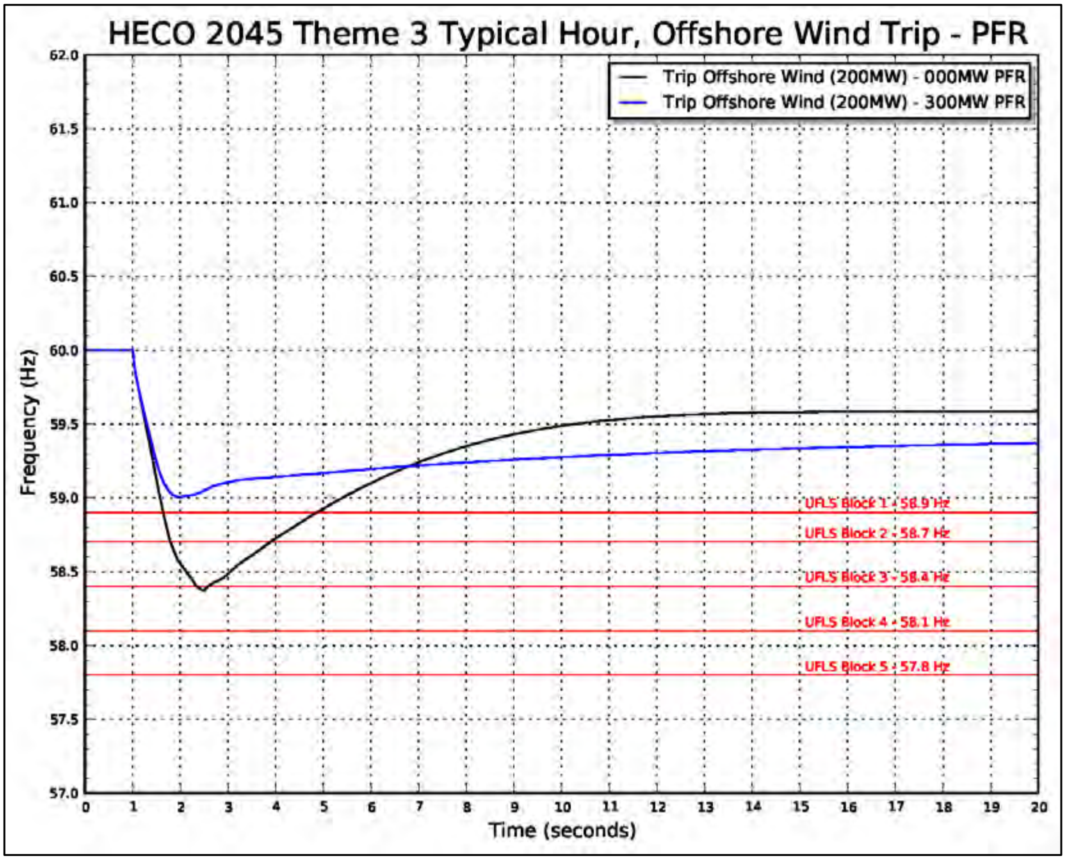


Figure O-49. Frequency Response Profile for PFR Typical Hour

Figure O-49 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 300 MW.

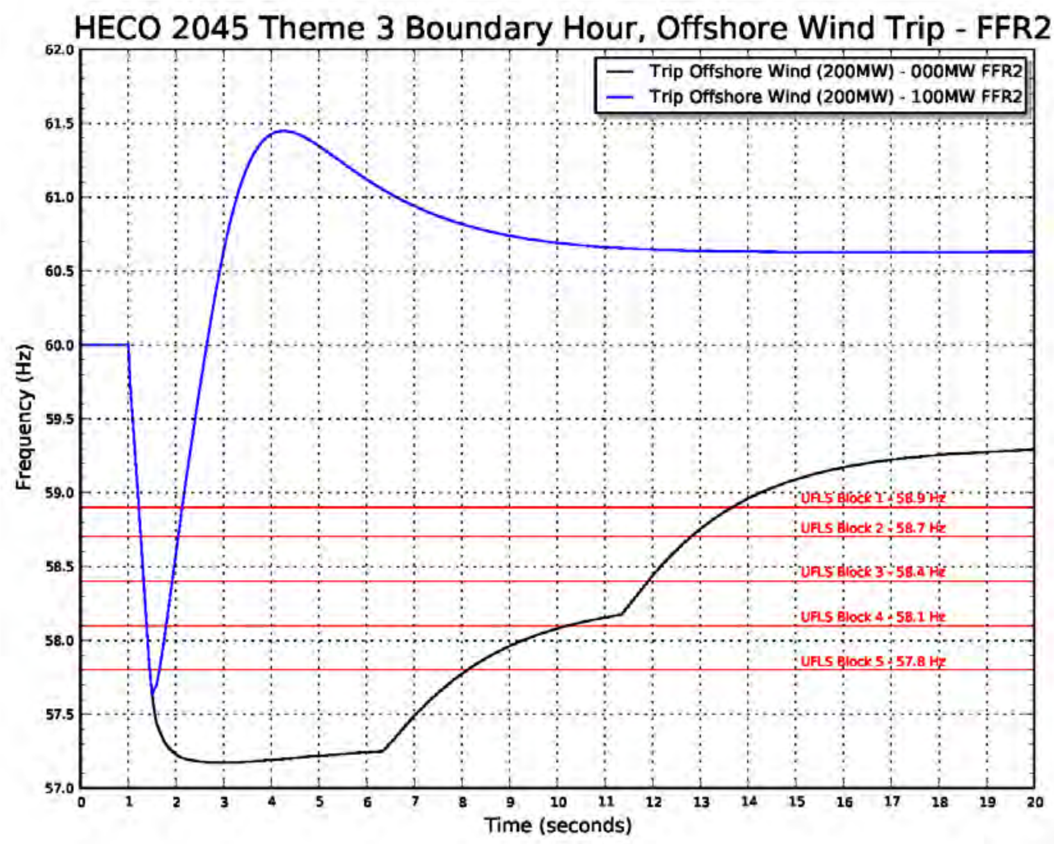


Figure O-50. Frequency Response Profile for FFR2 Boundary Hour

Figure O-50 shows the frequency response profile for a 200 MW cable trip of an offshore wind plant for the typical hour. System kinetic energy is 1664 MW-sec. Without FFR2, the frequency nadir reaches 57.2 Hz requiring 5 blocks of UFLS to stabilize system frequency. Simulations of 100 MW of FFR2 in conjunction with the 5 blocks of UFLS over compensates for this contingency, causing system frequency to exceed 61.4 Hz. The 30-cycle time delay is too long to dispatch FFR2, indicating that there is no amount of FFR2 that will bring the system into compliance with TPL-001.

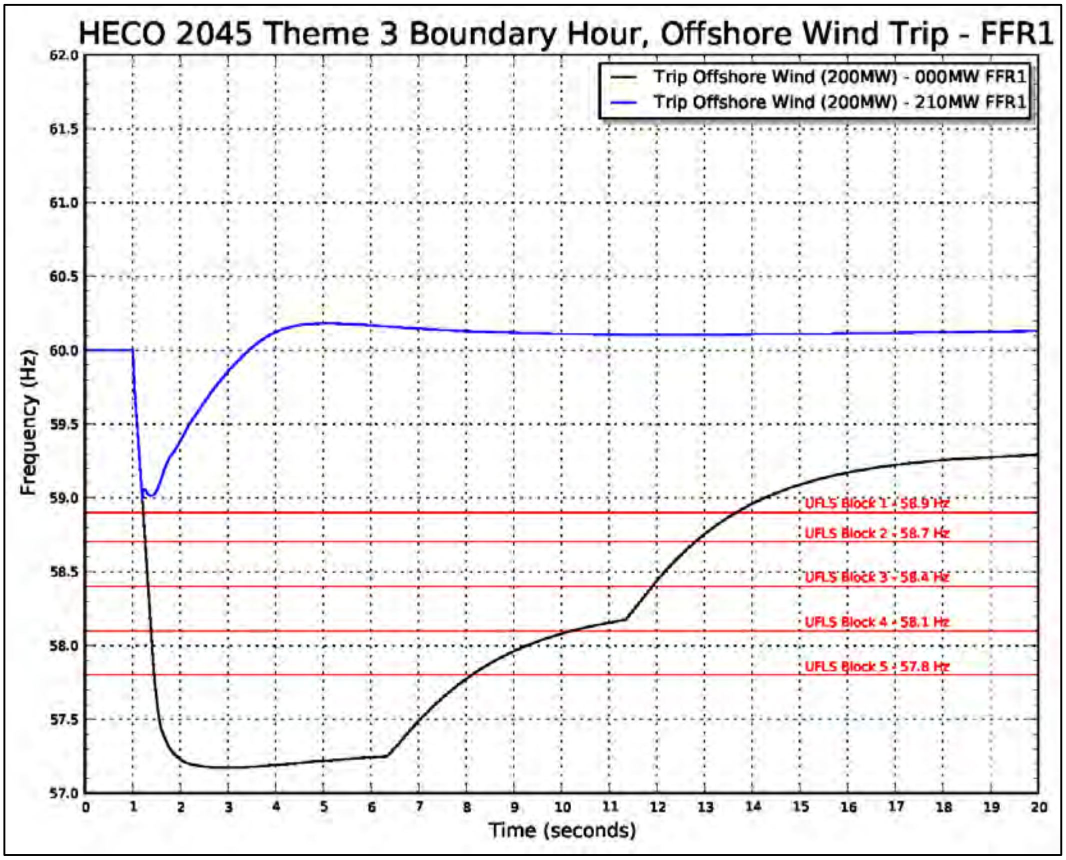


Figure O-51. Frequency Response Profile for FFR1 Boundary Hour

Figure O-51 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 210 MW.

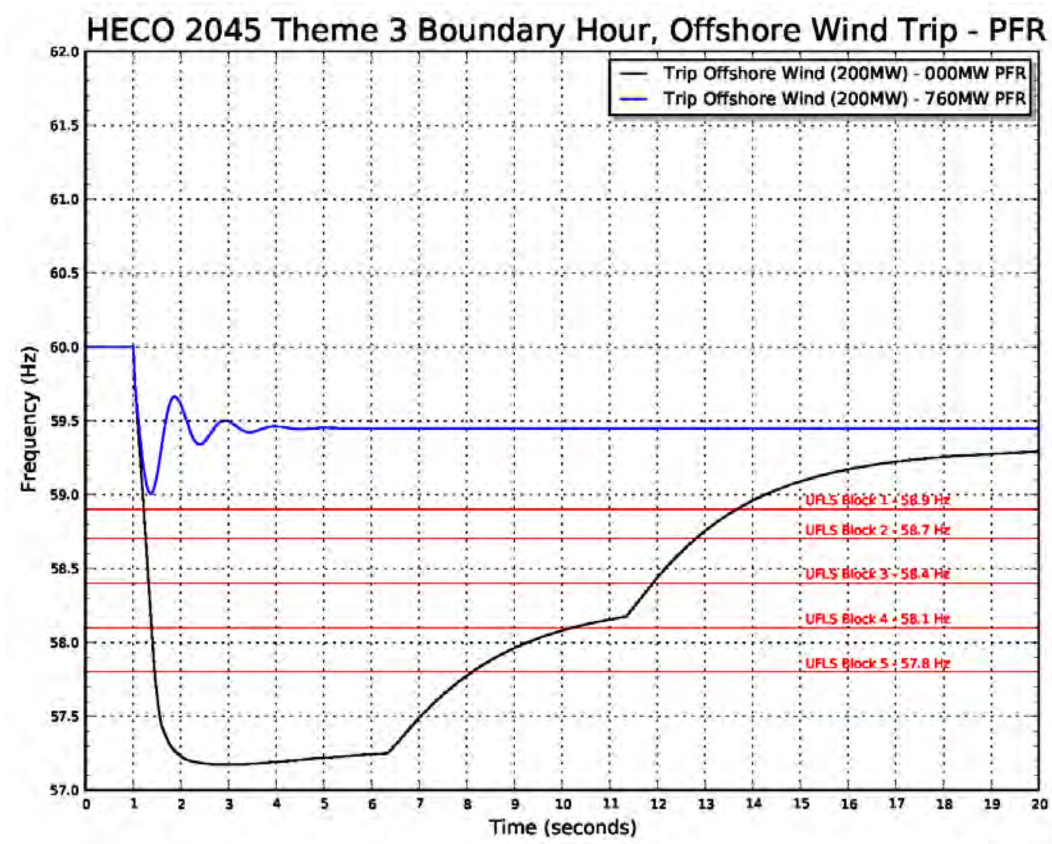


Figure O-52. Frequency Response Profile for PFR Boundary Hour

Figure O-52 shows the frequency response profile for this simulation. The capacity of PFR required to bring the system into compliance with TPL-001 is 760 MW.

138 kV Fault Analysis

Simulations were performed for a 138 kV breaker failure on multiple transmission busses to determine rotor angle stability for the typical and boundary hours. There were no rotor angle stability issues for the typical hour.

2045 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Typical Hour Condition	Boundary Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Unstable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	AES	323	15	AES Gen	Stable	Unstable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Unstable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Unstable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Unstable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Unstable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Unstable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Unstable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Unstable	Unstable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Unstable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Unstable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Unstable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Unstable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Unstable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Unstable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Unstable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Unstable	Unstable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Unstable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Unstable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Unstable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Unstable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Unstable	Unstable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Unstable	Unstable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Unstable	Unstable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Unstable	Unstable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Unstable	Unstable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Unstable	Unstable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Unstable	Unstable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Unstable	Unstable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Unstable	Stable

Table O-21. Summary of Results for the 2045 Breaker Failure Analysis

Table O-21 shows the results of the breaker failure analysis. For the typical hour, only 24 simulations resulted in unstable operation. For the boundary hour, all but 3 simulations resulted in unstable operation. Further analyses will be performed to determine mitigation alternatives.

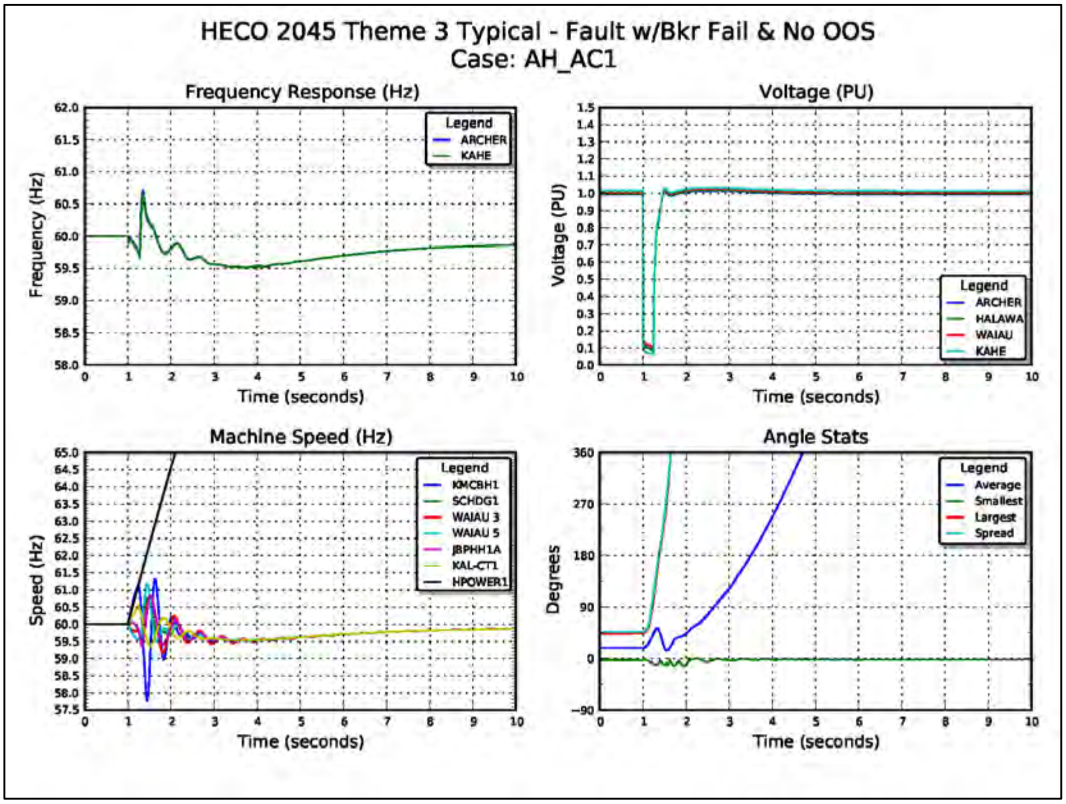


Figure O-53. System Performance for BKR 129 Failure Analysis

Figure O-53 shows four plots that illustrate unstable operation for a fault on the AES-CEIP 1 line and BKR 320 fails to operate. The Machine Speed plot shows HPOWER 1 (black) losing synchronism with the system. HPOWER 1 has a low inertia constant (2.57 MJ/MVA) that determines the shorter critical clearing time. More analysis is required to determine mitigation alternatives.

Summary

The O'ahu system does not meet the requirements of TPL-001. Simulations were performed to determine the capacity of FFR2, FFR1 and PFR required to the system into compliance with TPL-001 in 2019.

Compliance with TPL-001

The capacities of FFR2 and FFR1 required to meet TPL-001 is 150 MW for the typical hour and 160 MW for the boundary hour. The capacities are equivalent because system inertia is relatively high so the 18-cycle delay in deployment of FFR2 has no impact in the frequency response profile.

A sensitivity analysis was performed if AES were dispatch to a lower output. The capacity of FFR2 and FFR1 required to meet TPL-001 with AES dispatch at 134 MW is 100 MW for the typical hour and 120 MW for the boundary hour. The capacities are higher than the 90 MW BESS assumption that was used for the PSIP because the production cost simulated hours were different from the analysis performed to size the 90 MW BESS. The table below shows that the FFR1 and PFR capacities will provide frequency response reserves through 2045 for Themes 2 and 3. More detailed analyses will be conducted to support the GO7 application that will be submitted to meet the service date of 2019.

Frequency Response Analysis TPL-001 Compliance				
Freq Response	Theme 3			
	2019		2019	
	Typical AES 201 MW	Boundary AES 201 MW	Typical AES 134 MW	Boundary AES 134 MW
FFR2	150	160	100	120
FFR1	150	160	100	120
PFR	-	-	-	-

Table O-22. Summary of Analysis to Meet TPL-001

Table O-22 shows the results of the FFR analysis to bring the system into compliance with TPL-001 for an AES turbine trip and the sensitivity analysis with AES dispatched to 134 MW.

Oah'u Frequency Response Analysis Results								
Freq Response	Theme 2						Theme 3	
	2023		2030		2045		2045	
	Typical KLCT 80 MW	Boundary GEST 120 MW	Typical Wind 133 MW	Boundary Wind 200 MW	Typical Wind 200 MW	Boundary Wind 200 MW	Typical Wind 200 MW	Boundary Wind 200 MW
FFR2	50	120	100	No Solution	No Solution	No Solution	130	No Solution
FFR1	50	120	110	180	150	160	120	210
PFR	-	-	310	690	470	580	300	760

Table O-23. Summary of Frequency Response Reserve Analysis

Table O-23 shows the results of the FFR2, FFR1, and PFR analysis. The 100 MW of FFR1 in 2019 for AES dispatched at 134 MW will meet the Theme 2 and Theme 3 FFR1 requirements through 2045. If 90 MW of FFR1 is installed in 2019, additional FFR2 and PFR will be required for Themes 2 and 3 to meet TPL-001.

MAUI COUNTY CANDIDATE PLANS

State of the System

Analyses was conducted to evaluate the Maui island system to determine if additional FFR is required to meet HI-TPL-001 in addition to the existing BESS installed as part of the Kahiawa Wind Farm .

Historical Contingency Events on Maui

On March 1, 2012, the system experienced the loss of two Maʻalaea generating units trip offline. The total system generation prior to the event was 155 MW. Maʻalaea M16 generating unit breaker opened at 13:32:35 with an output of 19.7 MW. The frequency decreased to 58.4 Hz and tripped Block 1 & 2 on UFLS for the frequency to recover. After a short recovery, M19 tripped offline with an output of 20.2 MW. The loss of M19 decreased the frequency to 57.7 Hz and triggered Block 3 on UFLS.

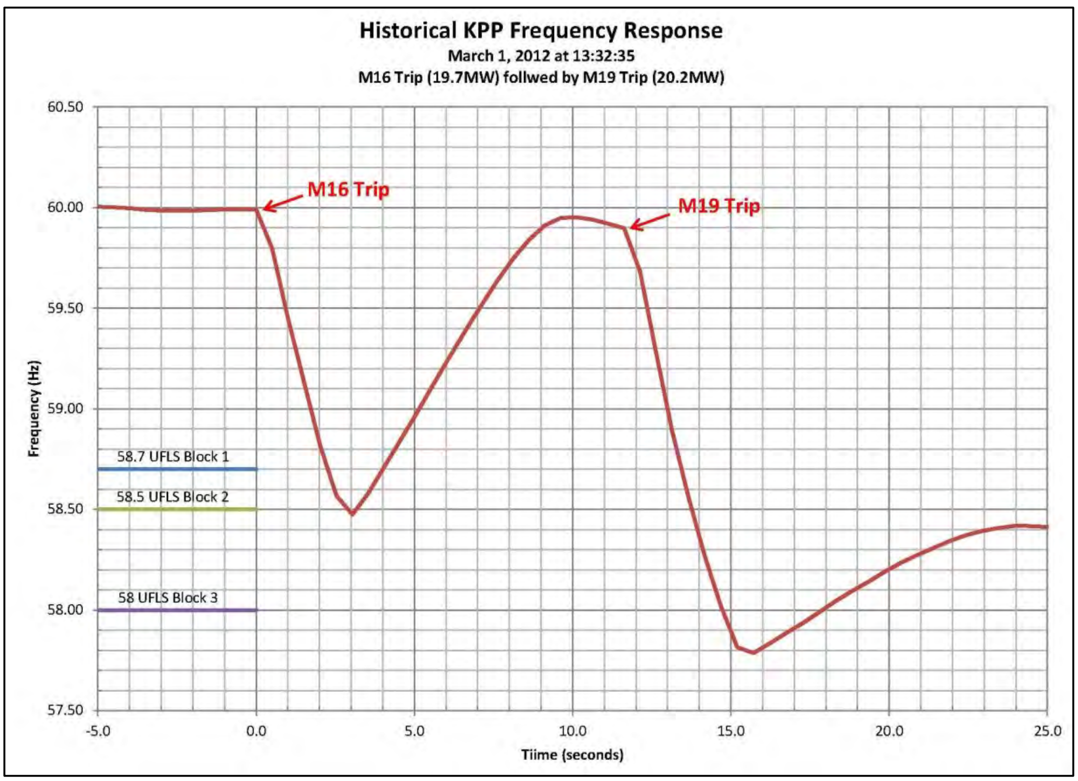


Figure O-54. Frequency Response Profile for Historic Events

Figure O-54 shows the frequency response profile for the M16 and M19 trip. The M16 trip causes the frequency nadir to breach 58.5 Hz that required 2 blocks of UFLS to stabilize system frequency.

2016

System security analysis was performed on two hours that were selected from the production cost analyses that represents a typical hour and a boundary condition.

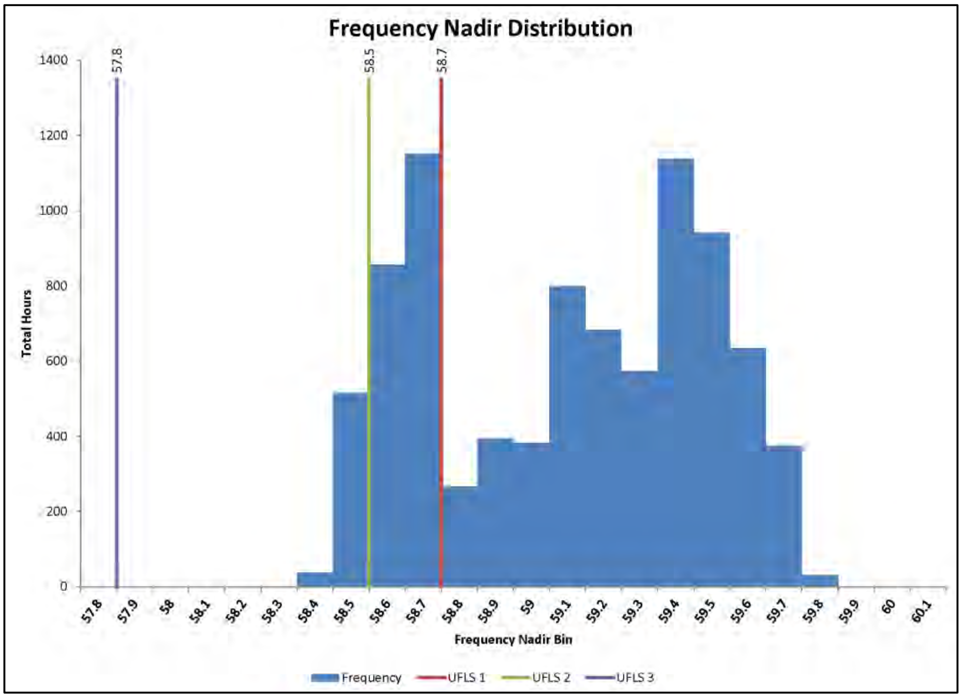


Figure O-55. Frequency Nadir Histogram for 2016

Figure O-55 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 516 hours was 2:00 PM on Monday, April 18. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 1:00 PM on Saturday, November 26. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

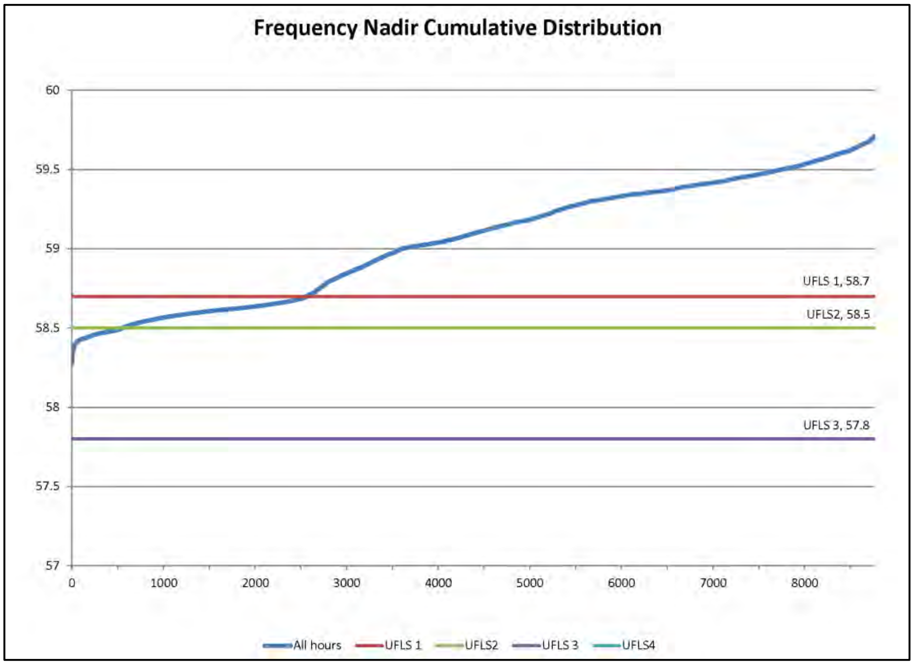


Figure O-56. Frequency Nadir Duration Curve for 2016

Figure O-56 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings					Maui 2016 (Typical) Mon 4/13/2016 Hour14			Maui 2016 (Boundary) Sat 3/11/2045 Hour13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	13.5	47	5.0	6.5	2.0	5.0	6.5	2.0
M14	20.0	5.9	2.02	28.8	58	13.5	6.5	7.6			
M15	13.0	6.0	2.46	18.5	46	8.0	5.0	2.0			
M16	20.0	5.9	2.02	26.8	54	13.5	6.5	7.6			
Kahului 1	4.8	2.3	5.23	6.3	33						
Kahului 2	4.9	2.3	5.23	6.3	33						
M17	19.5	5.9	2.02	26.8	54	6.0	13.5	0.1	13.0	6.5	7.1
M18	12.8	3.0	2.46	18.5	46				4.0	8.8	1.0
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
Total Wind	72	0				58			55		
-KWP	30	0				28			29		
-Auwahi	21	0				21			21		
-KWPII	21	0				9			5		
DG-PV	98.96	0				73			59		
Total System MVA							128			72	
Total Kinetic Energy							347			235	
Total Load							177			140	
Total Thermal Generation							51			27	
Total Renewable Generation							131			114	
Total Generation							182			141	
Excess Generation							5			1	
Regulation Requirement[1]							0			0	
Total Up Regulation							45			28	
Total Down Regulation							21			12	
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		5.0	59.3Hz Output		4.0
	60.5Hz Capacity			29.9		60.5Hz Output		22.0	60.5Hz Output		17.8

Table O-24. Unit Commitment and Dispatch for 2016

Table O-24 shows the unit commitment and dispatch schedules for the typical hour (4/18/2016 at 2:00 PM) and boundary hour (11/26/2016 at 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

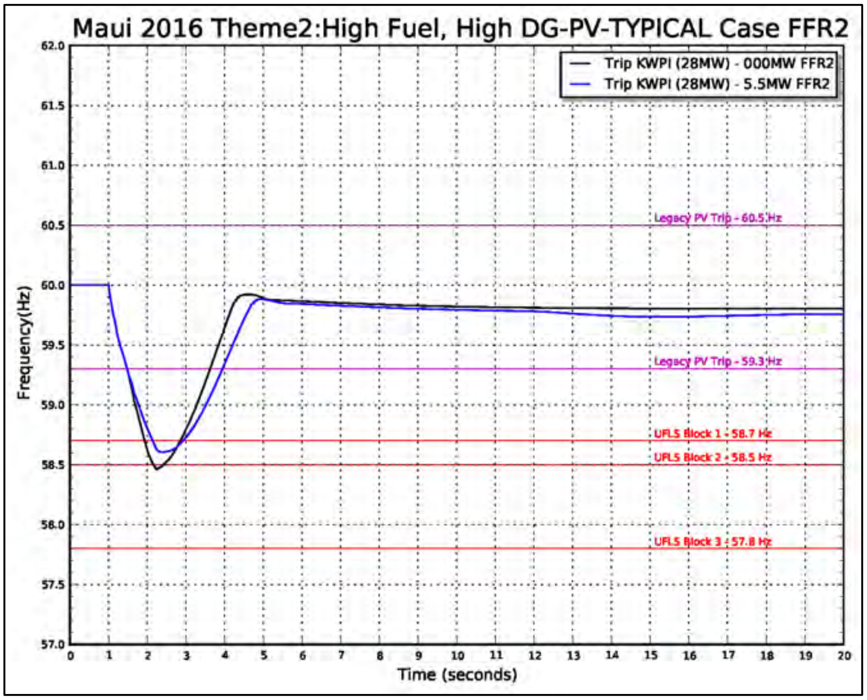


Figure O-57. Frequency Response Profile for FFR2 Typical Hour

Figure O-57 shows the frequency response profile for a KWP wind plan trip at 28 MW for a typical hour. System kinetic energy is 347 MW-sec and the capacity of legacy PV that will disconnect from the system is 4 MW. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001, only one UFLS block, is 5.5 MW.

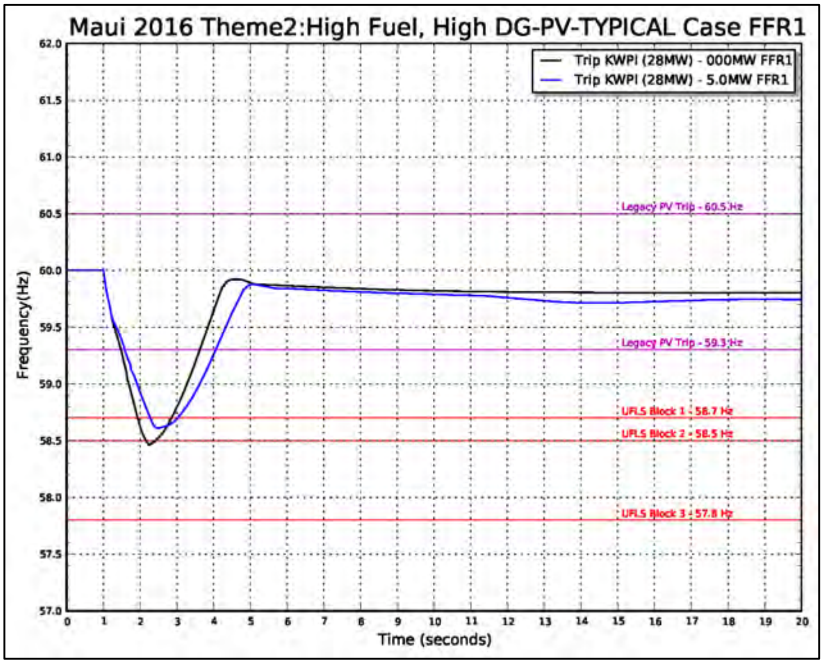


Figure O-58. Frequency Response Profile for FFR1 Typical Hour

Figure O-58 shows the frequency response profile for the FFR1 analysis for the typical hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

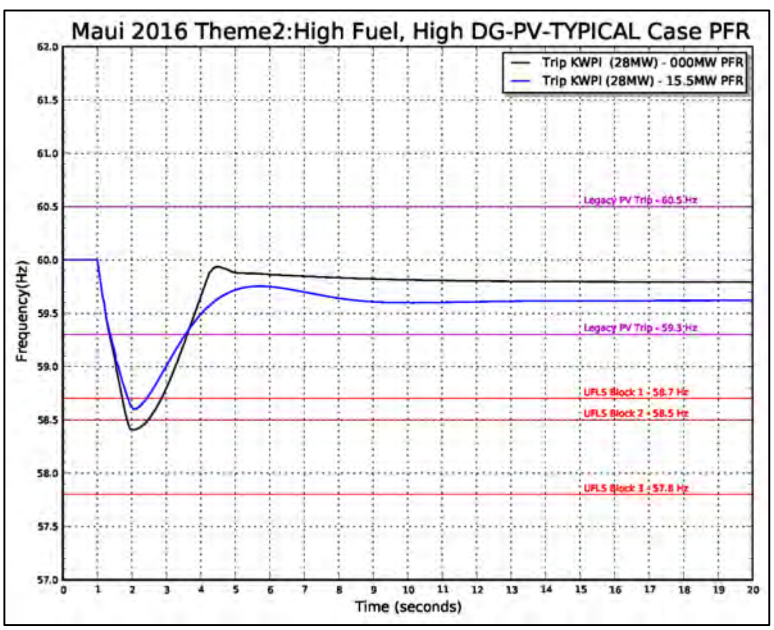


Figure O-59. Frequency Response Profile for PFR Typical Hour

Figure O-59 shows the frequency response profile for the PFR analysis for the typical hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 15.5 MW.

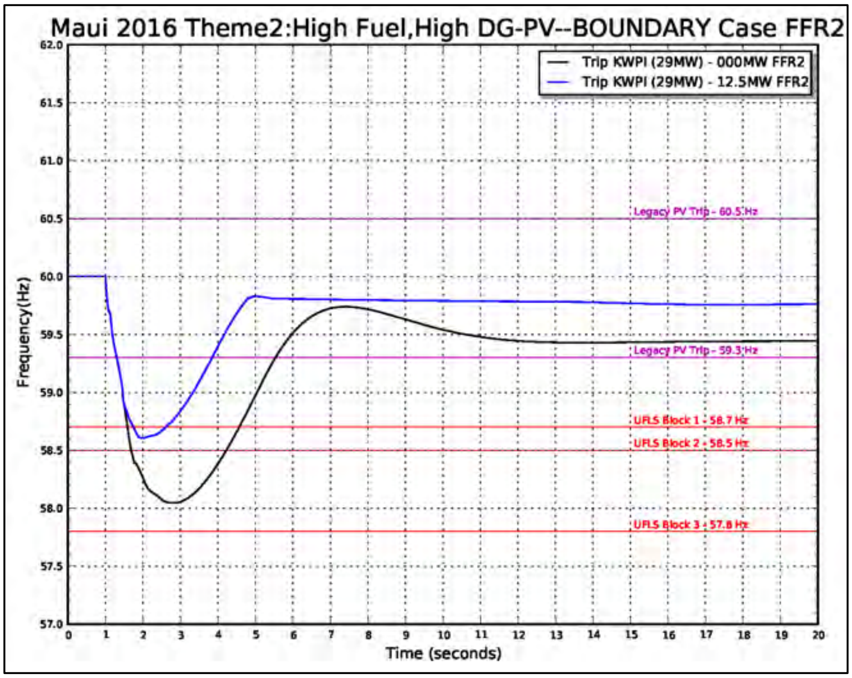


Figure O-60. Frequency Response Profile for FFR2 Boundary Hour

Figure O-60 shows the frequency response profile for a KPW wind plan trip at 29 MW for a typical hour. System kinetic energy is 235 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5 MW. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5.5 MW.

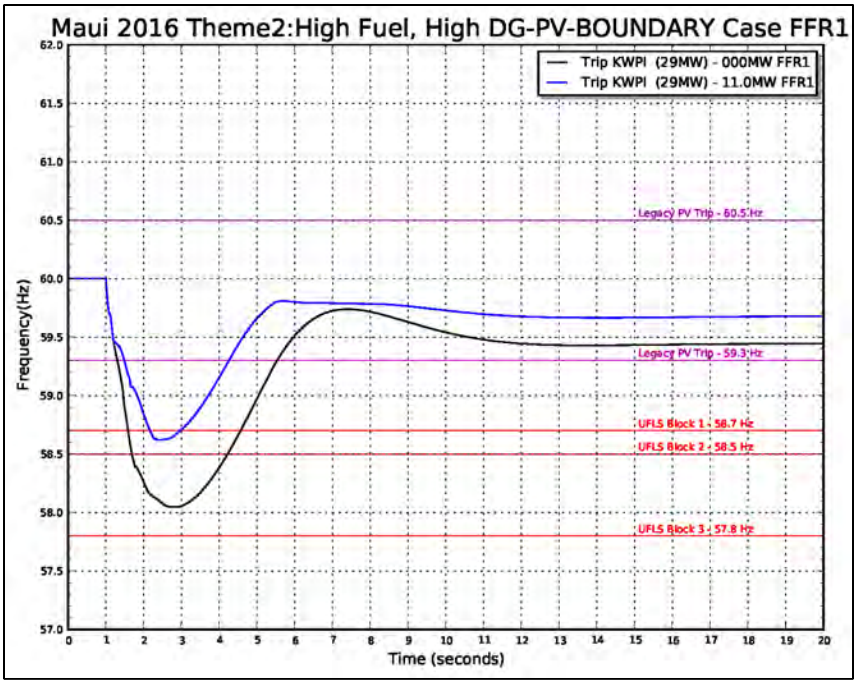


Figure O-61. Frequency Response Profile for FFR1 Boundary Hour

Figure O-61 shows the frequency response profile for the FFR1 analysis for the boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 11 MW.

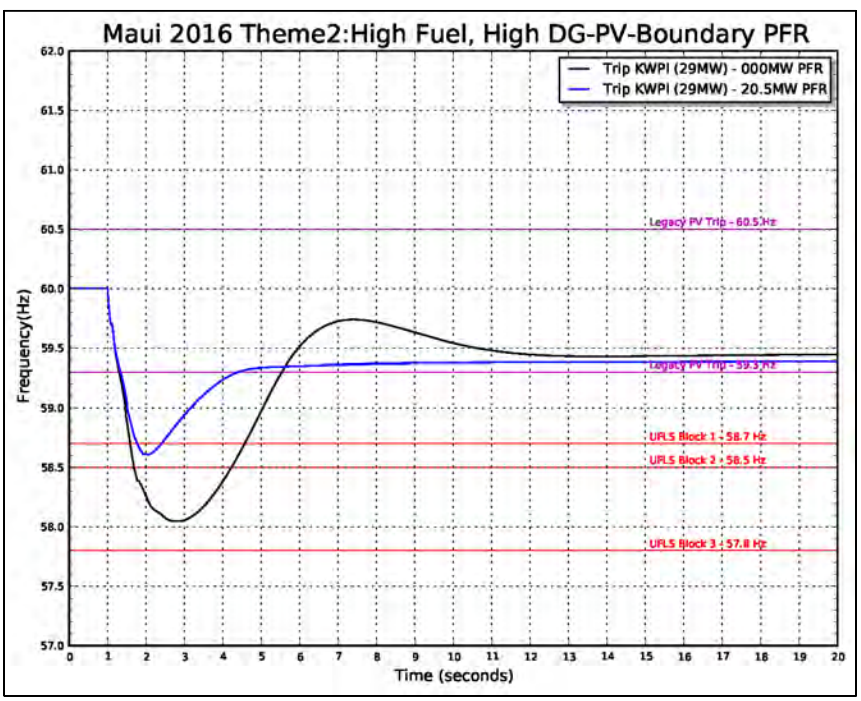


Figure O-62. Frequency Response Profile for PFR Boundary Hour

Figure O-62 shows the frequency response profile for the PFR analysis for the boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 20.5 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations for both normally cleared faults and delayed cleared faults did not produce and system stability issues but some faults triggered loss of generation events.

2016 69 kV and 23 kV Fault Delayed ClearingAnalysis			
Circuit Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
Maalaea-Kihei	Kihei	Stable	Stable/Loadshed
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable/Loadshed
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable/Loadshed
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Stable	Stable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Stable	Stable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-25. Summary of Results for the 2016 Fault Analysis

Table O-25 summarized the results of the delayed clearing fault analysis. There were three simulations for the boundary hour that resulted in load shedding.

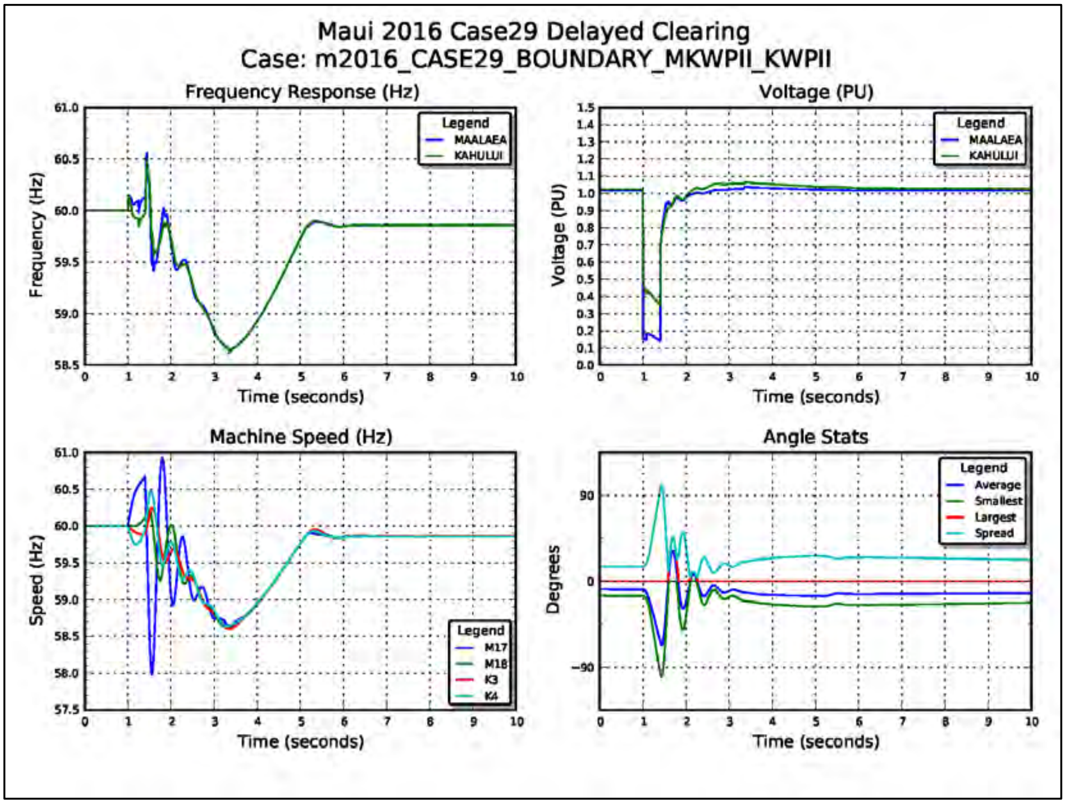


Figure O-63. System Performance for Delayed Clearing Analysis

Figure O-63 shows four plots that illustrate loss of DG-PV due a delayed clearing fault on the Maʻalaea-KWP II circuit for the boundary hour. The system frequency peak is greater than 60.5 Hz so approximately 18 MW of legacy will disconnect from the system.

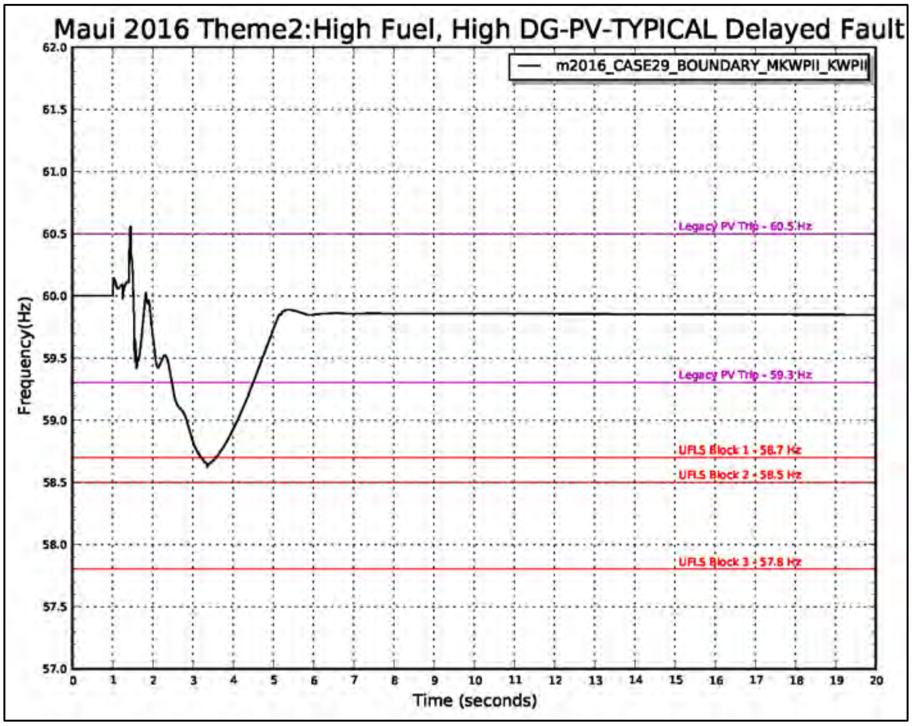


Figure O-64. Frequency Response Profile for Delayed Clearing Fault

Figure O-64 shows the frequency response profile for the delayed clearing fault. System performance meets the requirements of TPL-001.

2019—Compliance with TPL-001

Simulations were performed for the typical and boundary hours to determine the system requirements to bring the system into compliance with TPL-001 for the largest loss of generation contingency.

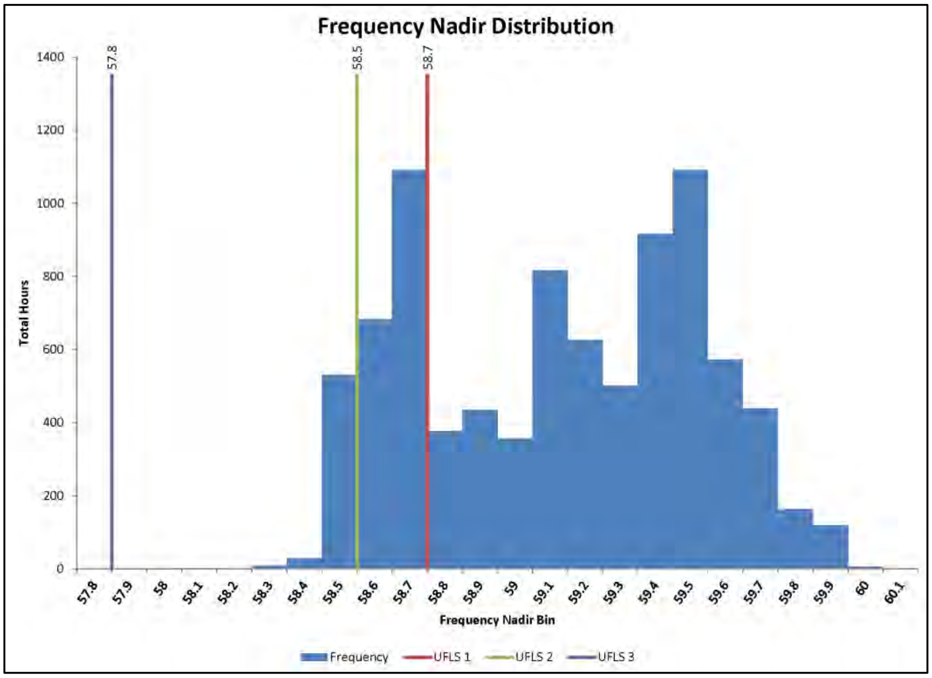


Figure O-65. Frequency Nadir Histogram for 2019

Figure O-65 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 530 hours was 2:00 PM on Monday, December 16. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 2:00 PM on Sunday, March 17. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires two blocks of UFLS to stabilize system frequency.

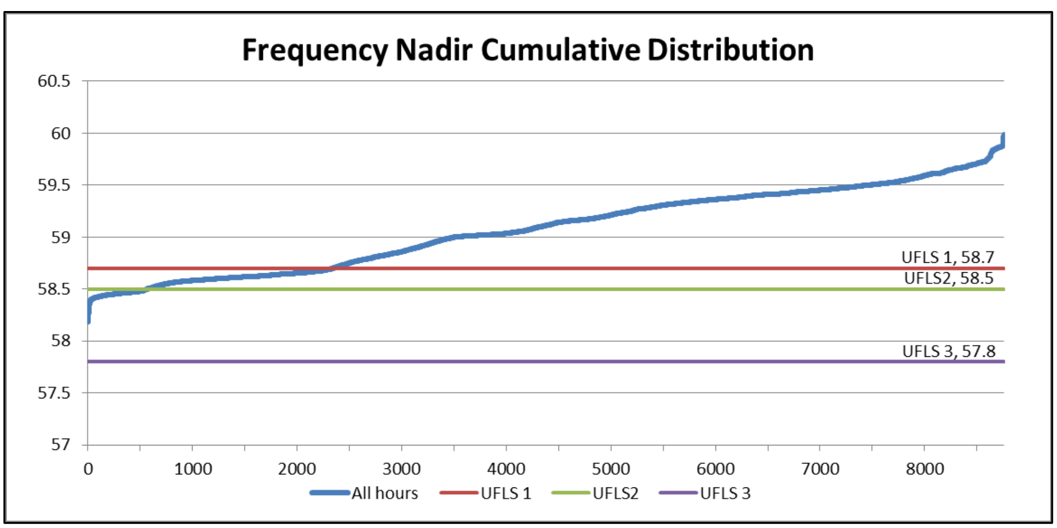


Figure O-66. Frequency Nadir Duration Curve for 2019

Figure O-66 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings					Maui 2019 (Typical) Mon 12/16/2019 Hour14			Maui 2019 (Boundary) Sun 3/17/2019 Hour14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	13.5	47	5.0	6.5	2.0	5.0	6.5	2.0
M14	20.0	5.9	2.02	28.8	58	9.0	11.0	3.1	8.0	12.0	2.1
M15	13.0	4.0	2.46	18.5	46	4.0	9.0	0.0	4.0	9.0	0.0
M16	20.0	5.9	2.02	26.8	54	9.0	11.0	3.1	8.0	12.0	2.1
Kahului 1	4.8	2.3	5.23	6.3	33						
Kahului 2	4.9	2.3	5.23	6.3	33						
M17	19.5	5.9	2.02	26.8	54	6.0	13.5	0.1			
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
Total Wind	72	0				70			53		
-KWP	30	0				28			30		
-Auwahi	21	0				21			2		
-KWPII	21	0				21			21		
DG-PV	120.3	0				65			92		
Station PV	5.74	0				3			0		
Total System MVA							128			101	
Total Kinetic Energy							347			293	
Total Load							170			169	
Total Thermal Generation							38			30	
Total Renewable Generation							138			145	
Total Generation							176			175	
Excess Generation							6			6	
Regulation Requirement[1]							0			0	
Total Up Regulation							58			46	
Total Down Regulation							10			8	
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		3.6	59.3Hz Output		5.2
	60.5Hz Capacity			29.9		60.5Hz Output		16.1	60.5Hz Output		22.8

Table O-26. Unit Commitment and Dispatch for 2019

Table O-26 shows the unit commitment and dispatch schedules for the typical hour (12/16/2019 at 2:00 PM) and boundary hour (3/17/2019 at 2:00 PM).

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

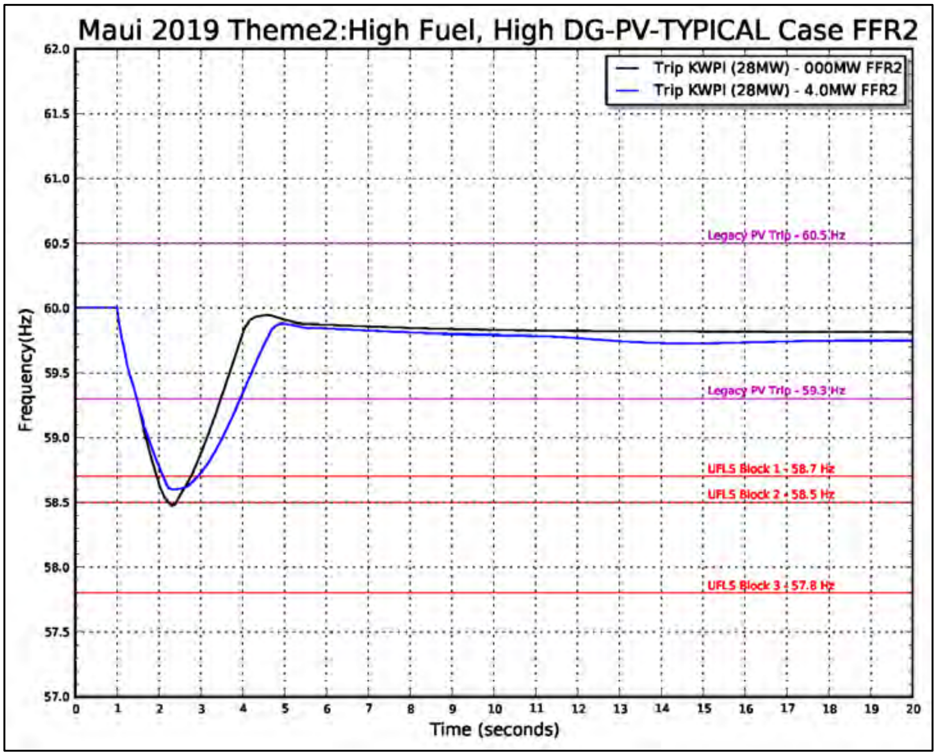


Figure O-67. Frequency Response Profile for FFR2 Typical Hour

Figure O-67 shows the frequency response profile for a KWP wind plant trip at 28 MW output for a typical hour. System kinetic energy is 347MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 3.6 MW. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 4 MW.

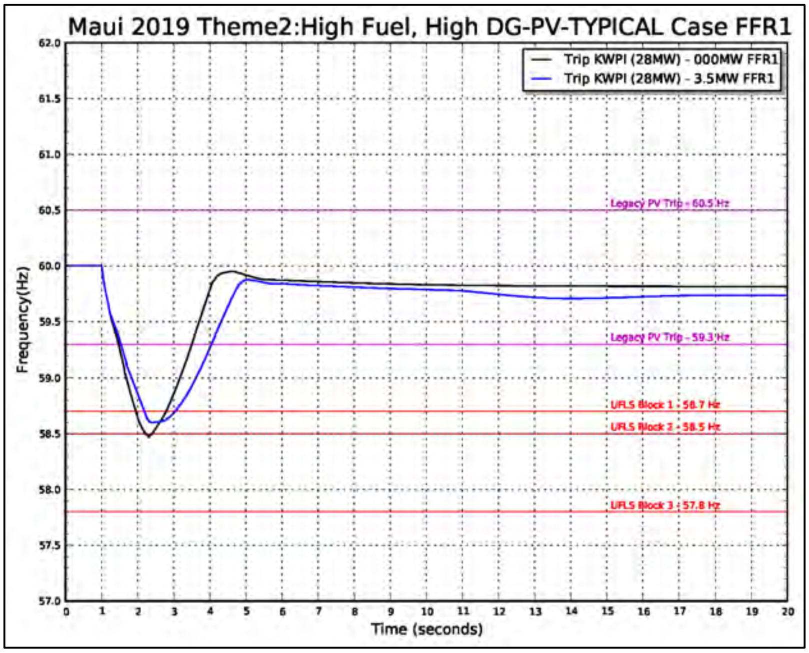


Figure O-68. Frequency Response Profile for FFR1 Typical Hour

Figure O-68 shows the frequency response profile for the FFR1 analysis for a typical hour. The capacity of FFR1 required to meet TPL-001 is 3.5 MW.

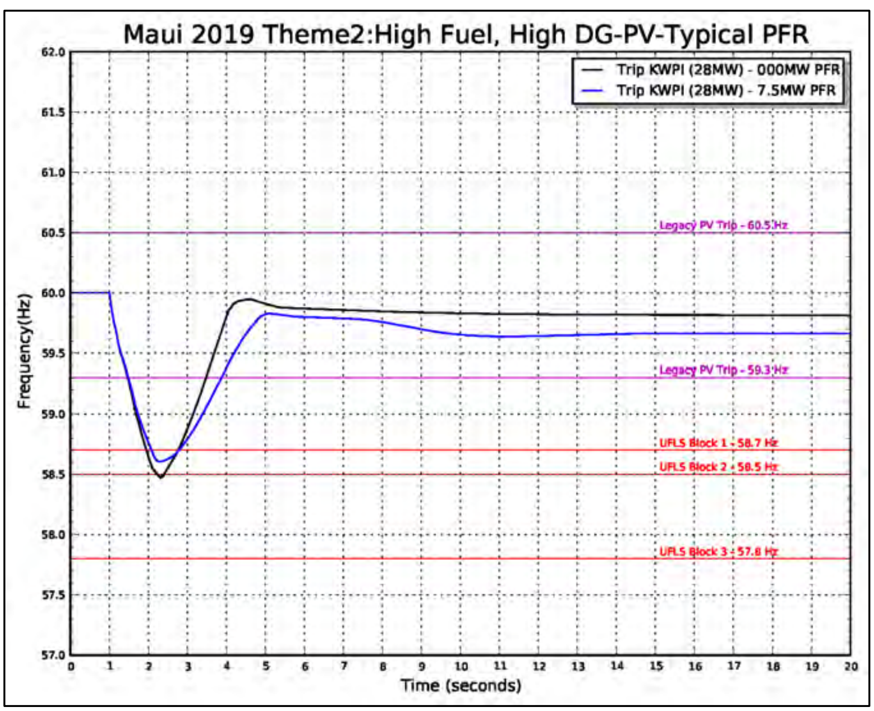


Figure O-69. Frequency Response Profile for PFR Typical Hour

Figure O-69 is the frequency response profile for the PFR analysis for the typical hour. The capacity of PFR required to meet TPL-001 is 7.5 MW.

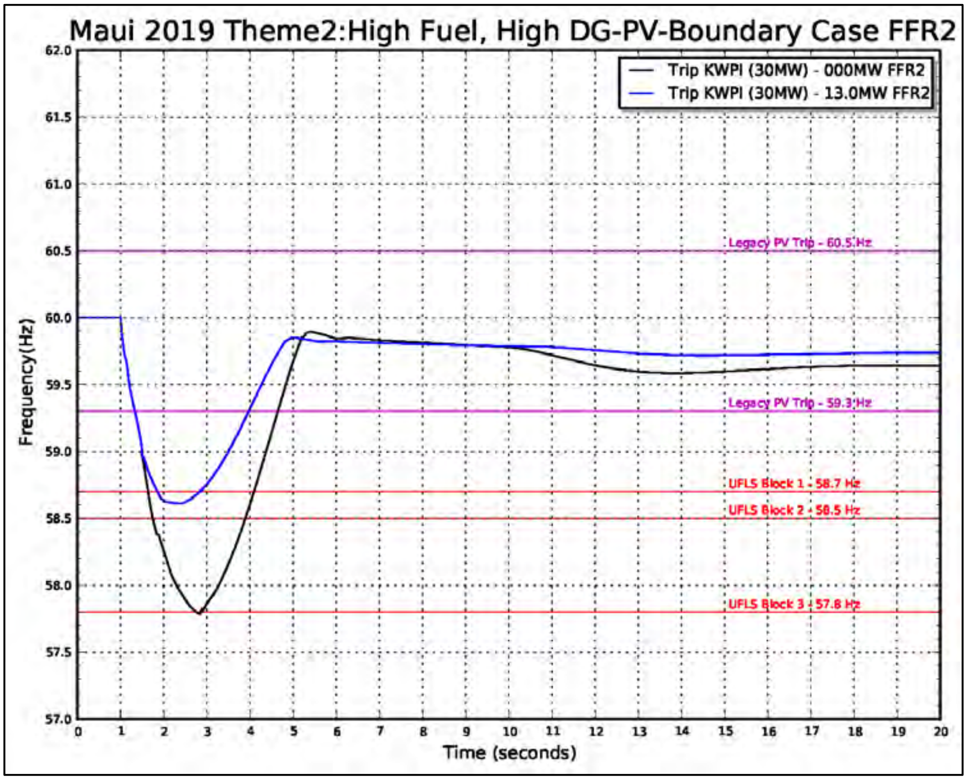


Figure O-70. Frequency Response Profile for FFR2 Boundary Hour

Figure O-70 shows the frequency response profile for a KWP wind plant trip at 30 MW for the boundary hour. System kinetic energy is 293 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.2 MW. With no FFR, the frequency nadir is 57.5 Hz and three blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW.

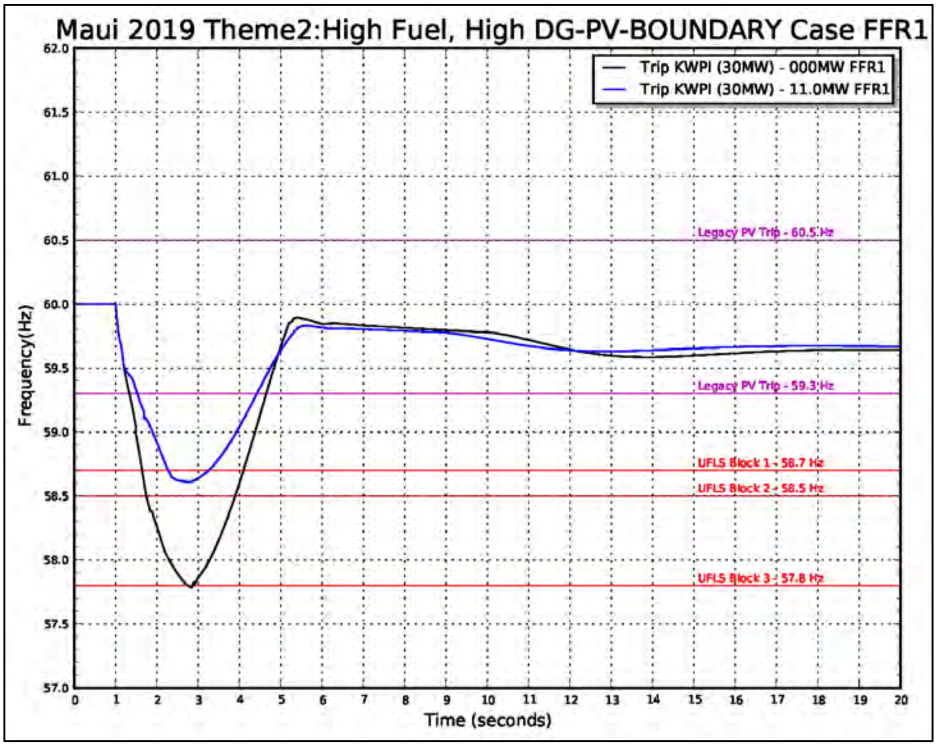


Figure O-71. Frequency Response Profile for FFR1 Boundary Hour

Figure O-71 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to meet TPL-001 is 11 MW.

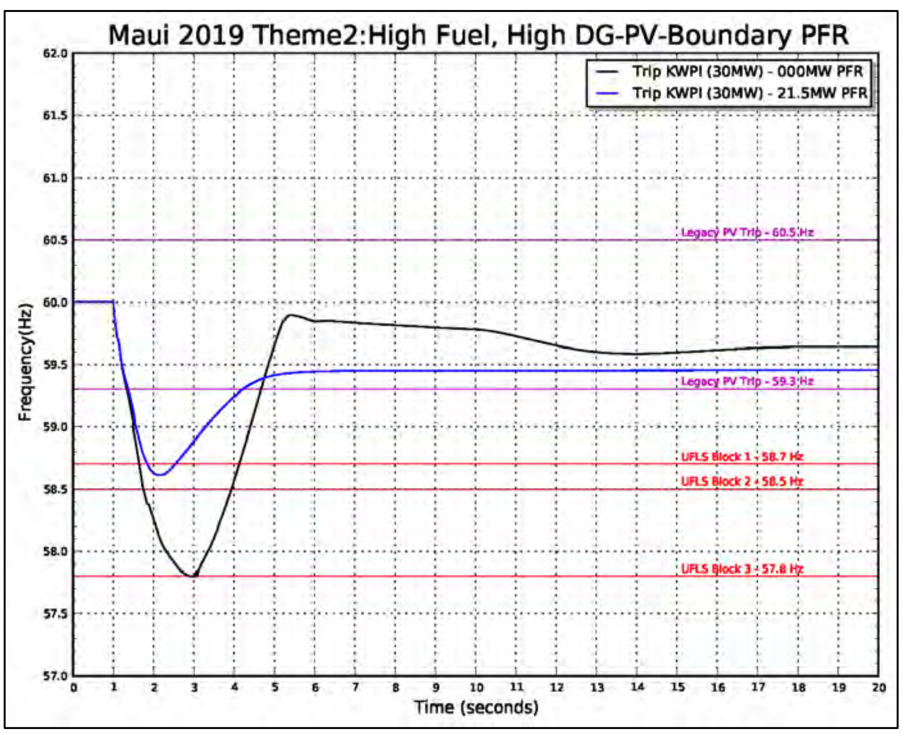


Figure O-72. Frequency Response Profile for PFR Boundary Hour

Figure O-72 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to meet TPL-001 is 21.5 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for both the normally cleared faults and delayed clearing faults did not produce any rotor angle stability issues or loss of generation from over frequency events.

2019 69Kv and 23 kV Fault Delayed Clearing Analysis			
Circuit Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Stable	Stable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Stable	Stable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-27. Summary of Results for the 20232019 Fault Analysis

Table O-27 summarizes the results of the delayed clearing fault analysis. There were no system security issues.

Theme 1 – Aggressive Renewables Plan

Summary

System security analyses were not performed on any resource plan for Theme 1. A high-level fatal flaw assessment was performed on the Theme 1 2045 plans by applying system security requirements for Themes 2 and 3.

Theme 2 – LNG Plan

2023

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

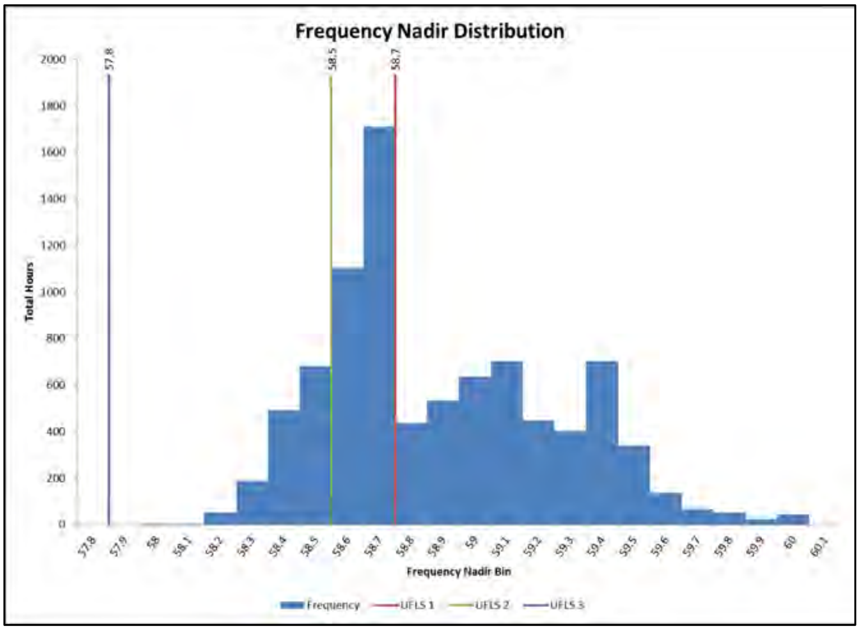


Figure O-73. Frequency Nadir Histogram for 2023

Figure O-73 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 682 hours was 12:00 PM on Friday, June 2. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 1:00 PM on Sunday, July 23. The frequency nadir range for the boundary hour was 57.9 – 58.0 Hz that would require 2 blocks of UFLS to stabilize system frequency.

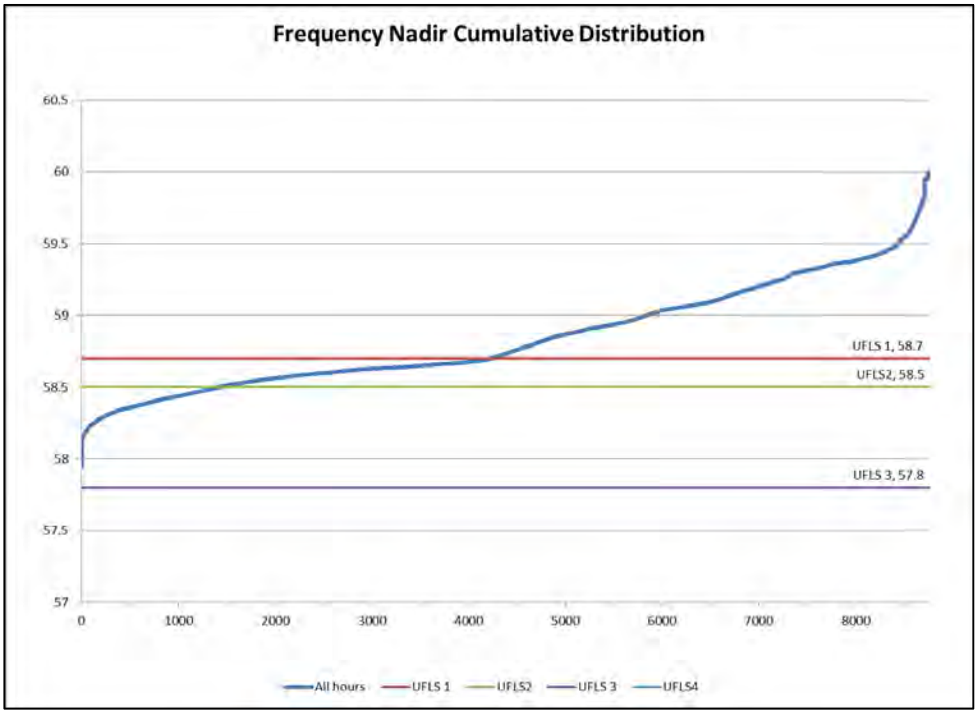


Figure O-74. Frequency Nadir Duration Curve 2023

Figure O-74 shows the frequency nadir duration curve for 2023.

Unit Commitment Order	Unit Ratings					Maui 2023 (Typical) Fri 6/2/2023 Hour12			Maui 2023 (Boundary) Sun 7/23/2023 Hour13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass1	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
M14	20.0	5.9	2.02	28.8	58	7.0	13.0	1.1	9.0	11.0	3.1
M15	13.0	6.0	2.46	18.5	46				6.0	7.0	0.0
M16	20.0	5.9	2.02	26.8	54						
M17	19.5	5.9	2.02	26.8	54	6.0	13.5	0.1			
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
ICE9_1	9.0	4.0	0.99	11.3	11						
ICE9_2	9.0	4.0	0.99	11.3	11						
Kahului 1	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser				
Kahului 2	0.0	0.0	2.62	6.3	16						
Kahului 3	0.0	0.0	3.27	13.5	44				0.0	Sync. Condenser	
Kahului 4	0.0	0.0	1.74	15.6	27	0.0	Sync. Condenser		0.0	Sync. Condenser	
Total Wind	132	0				62			50		
-KWP	30	0				23			29		
-Auwahi	21	0				19			1		
-KWPII	21	0				20			20		
-New Wind 1	30	0									
-New Wind 2	30	0									
DG-PV	122.7	0				87			97		
DER Grid Ex	22	0				24			17		
Total System MVA							103			101	
Total Kinetic Energy							243			262	
Total Load							186			182	
Total Thermal Generation							21			23	
Total Renewable Generation							173			164	
Total Generation							194			187	
Excess Generation							8			5	
Regulation Requirement[1]							0			0	
Total Up Regulation							27			18	
Total Down Regulation							1			3	
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		4.8	59.3Hz Output		5.3
	60.5Hz Capacity			29.9		60.5Hz Output		21.2	60.5Hz Output		23.6

Table O-28. Unit Commitment and Dispatch Schedule 2023

Table O-28 shows the unit commitment and dispatch schedules for the typical hour (6/2/2023 at 12:00 PM) and boundary hour (7/23/2023 at 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

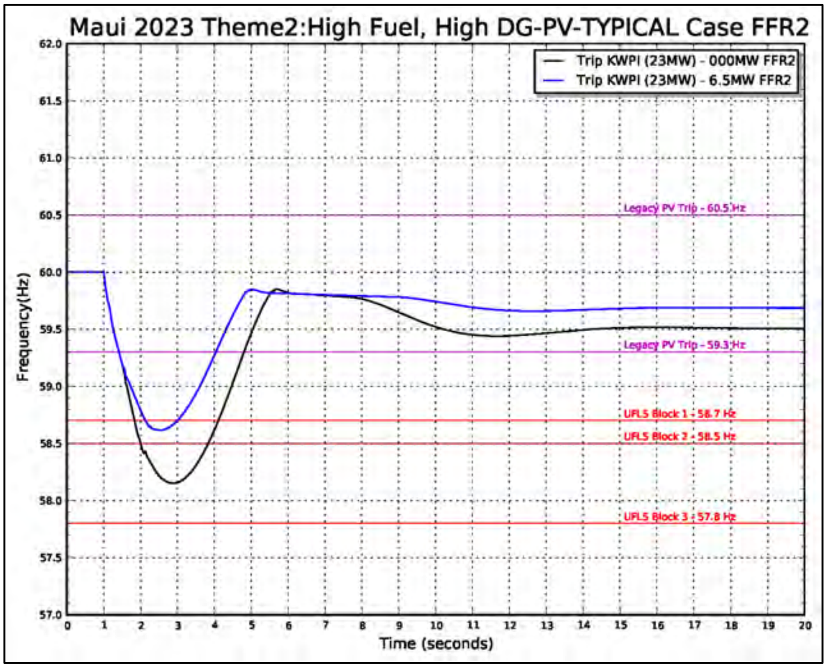


Figure O-75. Frequency Response Profile for FFR2 Typical Hour

Figure O-75 shows the frequency response profile for a KWP wind plant trip at 23 MW output for a typical hour. System kinetic energy is 243 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 4.8 MW. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 6.5 MW.

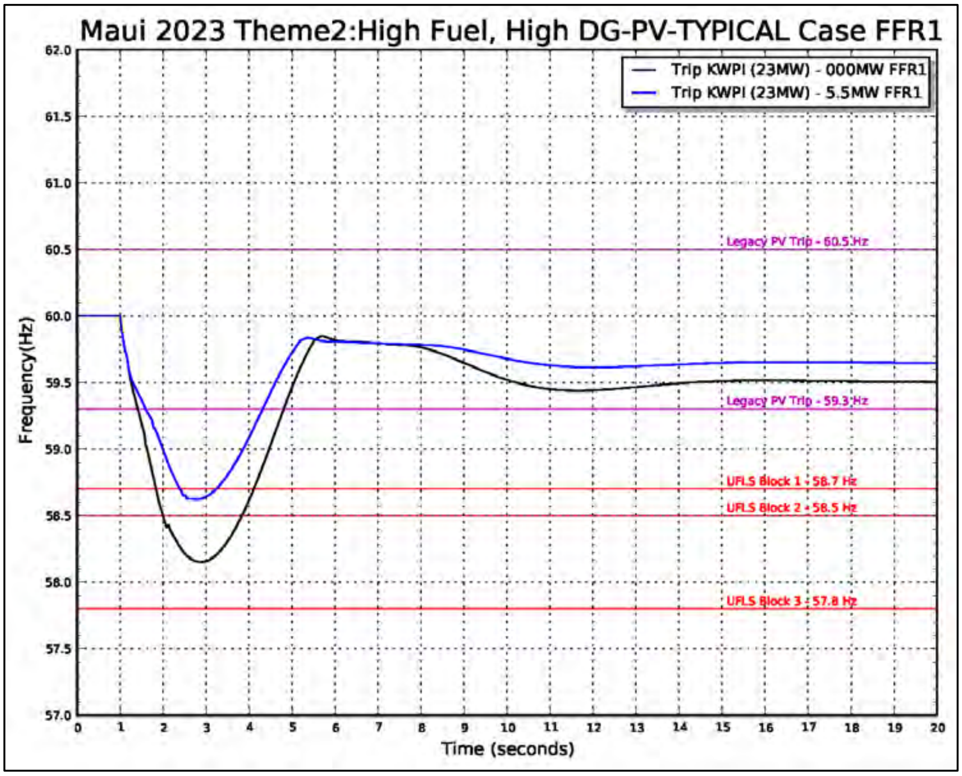


Figure O-76. Frequency Response Profile for FFR1 Typical Hour

Figure O-76 shows the frequency response profile for the FFR1 analysis for a typical hour. The capacity of FFR1 required to meet TPL-001 is 5.5 MW.

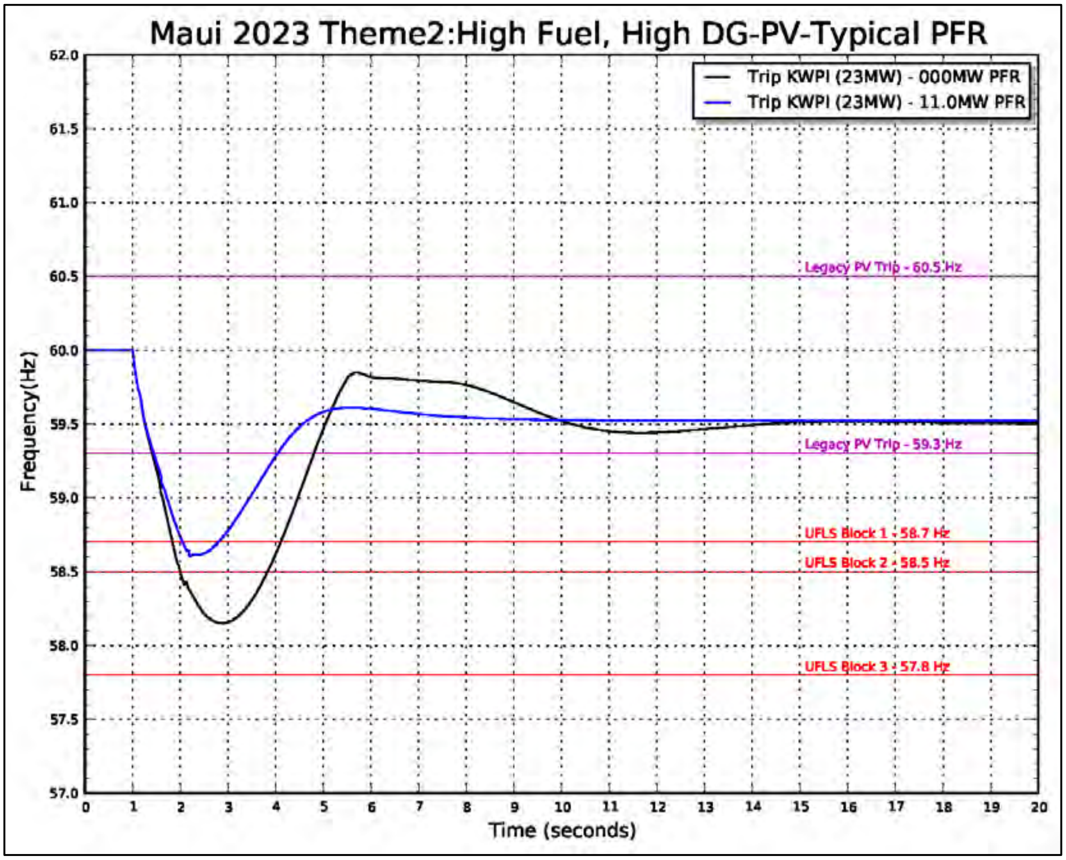


Figure O-77. Frequency Response Profile for PFR Typical Hour

Figure O-77 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to meet TPL-001 is 11 MW.

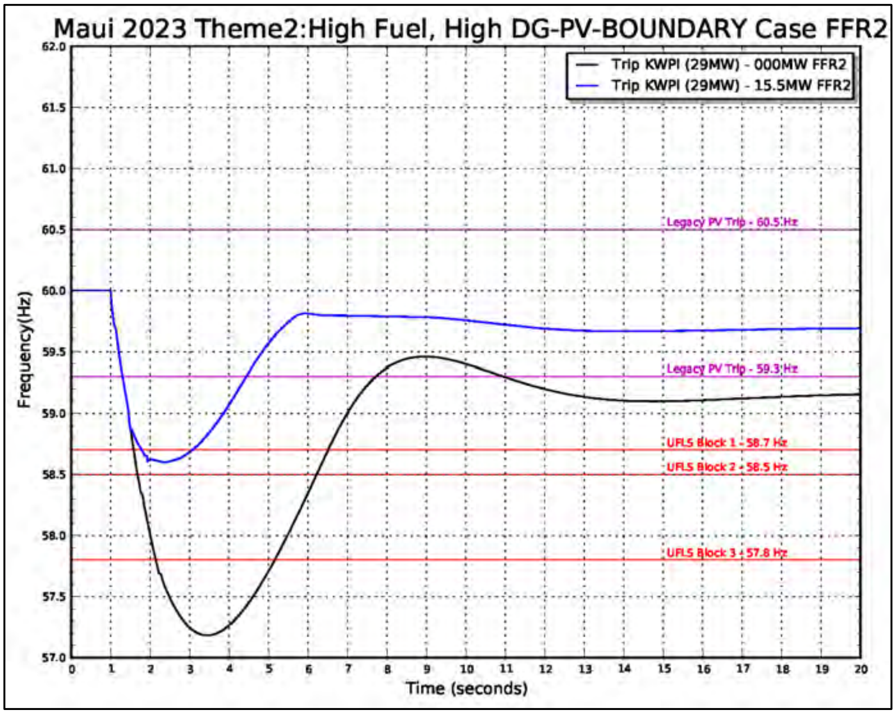


Figure O-78. Frequency Response Profile for FFR2 Boundary Hour

Figure O-78 shows the frequency response profile for a KWP wind plant trip at 29 MW output for a boundary hour. System kinetic energy is 262 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.3 MW. With no FFR, the frequency nadir breaches 57.2 Hz and three blocks of UFLS is required to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 15.5 MW.

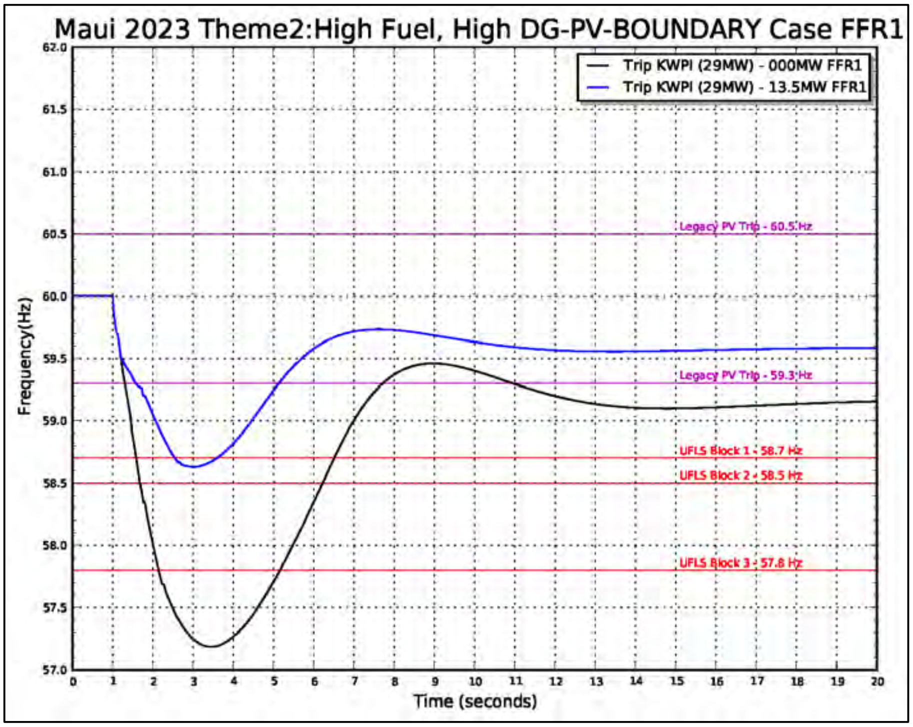


Figure O-79. Frequency Response Profile for FFR1 Boundary Hour

Figure O-79 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to meet TPL-001 is 13.5 MW.

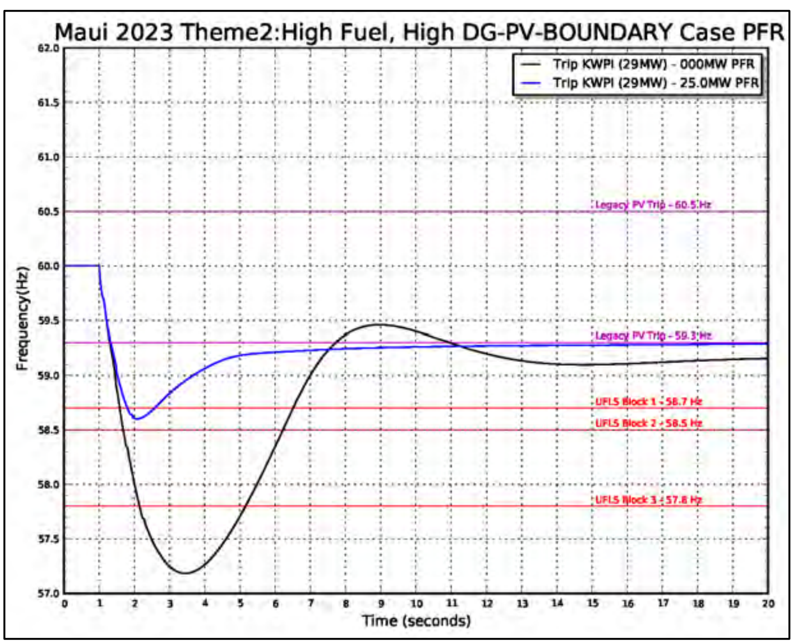


Figure O-80. Frequency Response Profile for PFR Boundary Hour

Figure O-80 shows the frequency response profile for the PFR analysis for a boundary hour. The capacity of PFR required to meet TPL-001 is 25 MW.

69 kV Fault analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for both the normally cleared faults and delayed clearing faults did not produce any rotor angle stability issues or loss of generation from over frequency events.

2023 69 kV and 23 kV Fault Normal Clearing Analysis			
Circuit Outage	**3-phase Fault Near**	**Typical Hour Condition**	**Boundary Hour Condition**
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Stable	Stable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Stable	Stable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-29. Summary of Results for the 2023 Fault Analysis

Table O-29 summarizes the results of the fault analysis. There was no stability or loss of load events for this analysis.

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

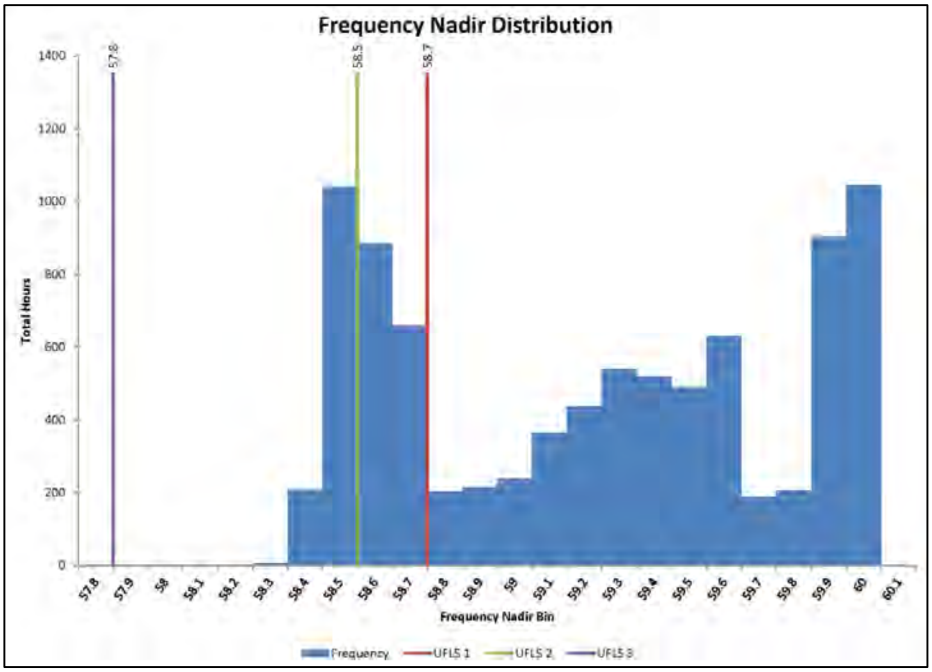


Figure O-81. Frequency Nadir Histogram for 2045

Figure O-81 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 516 hours was 2:00 PM on Monday, April 13. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 1:00 PM on Saturday, March 11. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

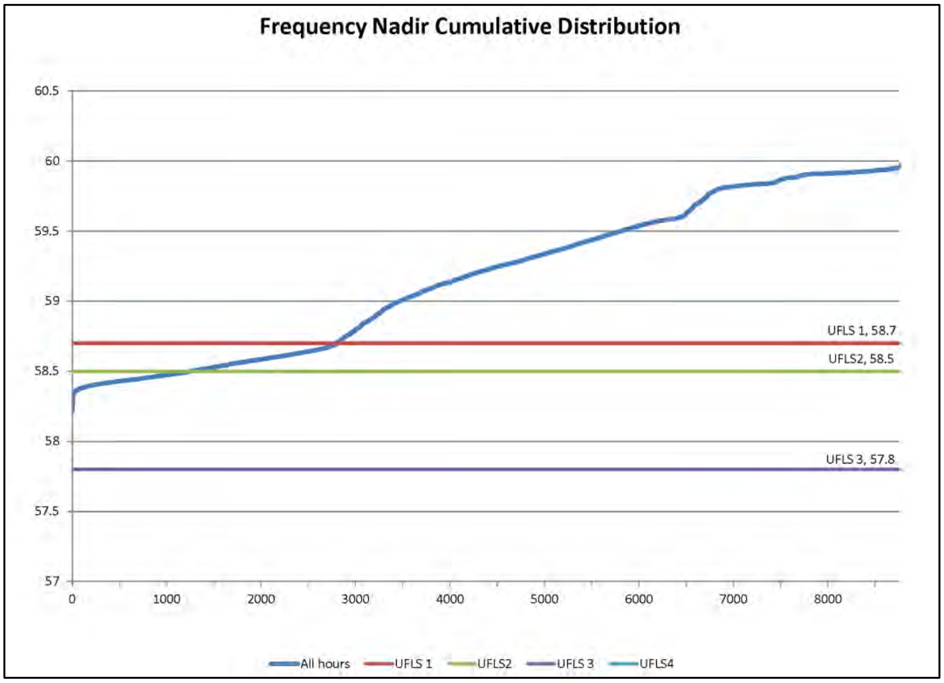


Figure O-82. Frequency Nadir Duration Curve for 2045

Figure O-82 shows the frequency nadir duration curve for 2045.

Unit Commitment Order	Unit Ratings					Maui 2045 (Typical) Tues 4/13/2045 Hour14			Maui 2045 (Boundary) Sun 3/19/2045 Hour15		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
M14	20.0	5.9	2.02	28.8	58						
M15	13.0	6.0	2.46	18.5	46						
M16	20.0	5.9	2.02	26.8	54						
M17	19.5	5.9	2.02	26.8	54						
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
ICE9_1	9.0	4.0	0.99	11.3	11						
ICE9_2	9.0	4.0	0.99	11.3	11						
Biomass1	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Biomass2	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Kahului 1	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 2	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 3	0.0	0.0	3.27	13.5	44	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 4	0.0	0.0	1.74	15.6	27	0.0	Sync. Condenser		0.0	Sync. Condenser	
SYNC COND	0.0	0.0	1.74	60.0	104	0.0	Sync. Condenser		0.0	Sync. Condenser	
Total Wind	252	0				59			52		
-KWP	30	0				28			30		
-Auwahi	21	0				11			3		
-KWPII	21	0				20			19		
-New Wind 1	30	0									
-New Wind 2	30	0									
-New Wind 3	30	0									
-New Wind 4	30	0									
-New Wind 5	30	0									
-New Wind 6	30	0									
DG-PV	139.3	0				84			87		
DER Grid Ex	328	0				114			96		
Total System MVA							50			50	
Total Kinetic Energy							382			382	
Total Load							235			215	
Total Thermal Generation							16			16	
Total Renewable Generation							257			235	
Total Generation							273			251	
Excess Generation							38			36	
Regulation Requirement[1]							0			0	
Total Up Regulation							24			24	
Total Down Regulation							16			16	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-30. Unit Commitment and Dispatch for 2045

Table O-30 shows the unit commitment and dispatch schedules for the typical hour (4/13/2045 at 2:00 PM) and boundary hour (3/19/2045 at 3:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

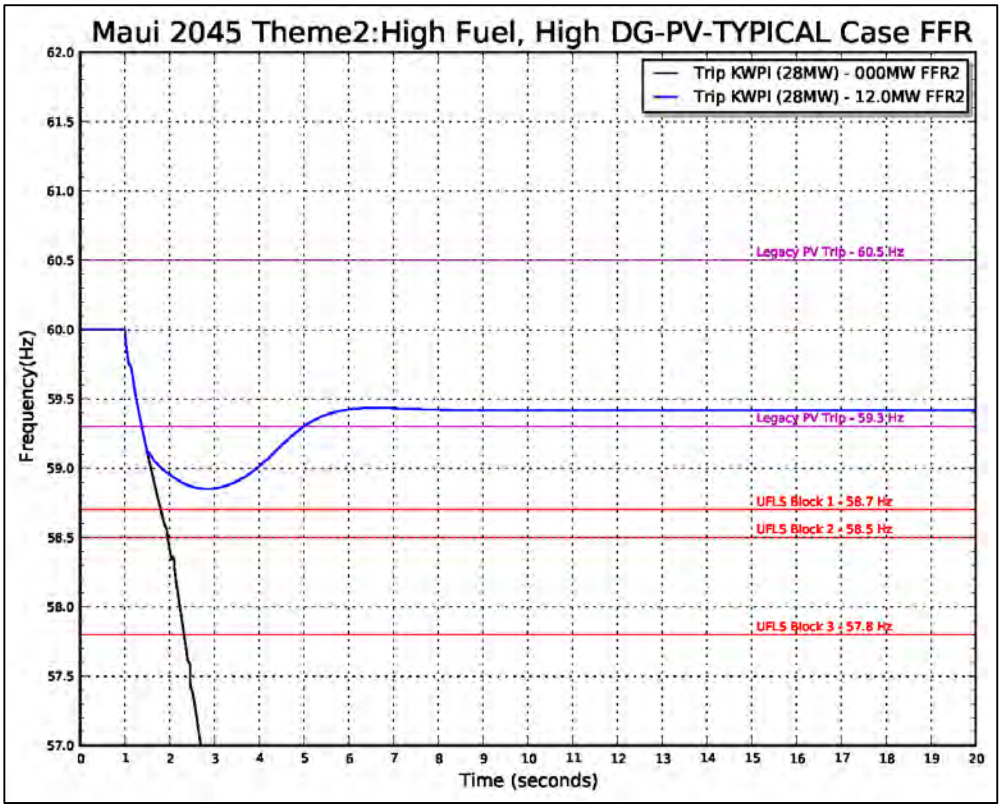


Figure O-83. Frequency Response Profile for FFR2 Typical Hour

Figure O-83 shows the frequency response profile for a KPW wind plan trip at 28 MW output for a typical hour. System kinetic energy is 382 MW-sec. With no FFR, the system will not survive a KWP trip. The total capacity of Grid Supply DG-PV is 114 MW so the first block of UFLS is actually a loss of generation so the UFLS has a cascading effect on declining frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 12 MW.

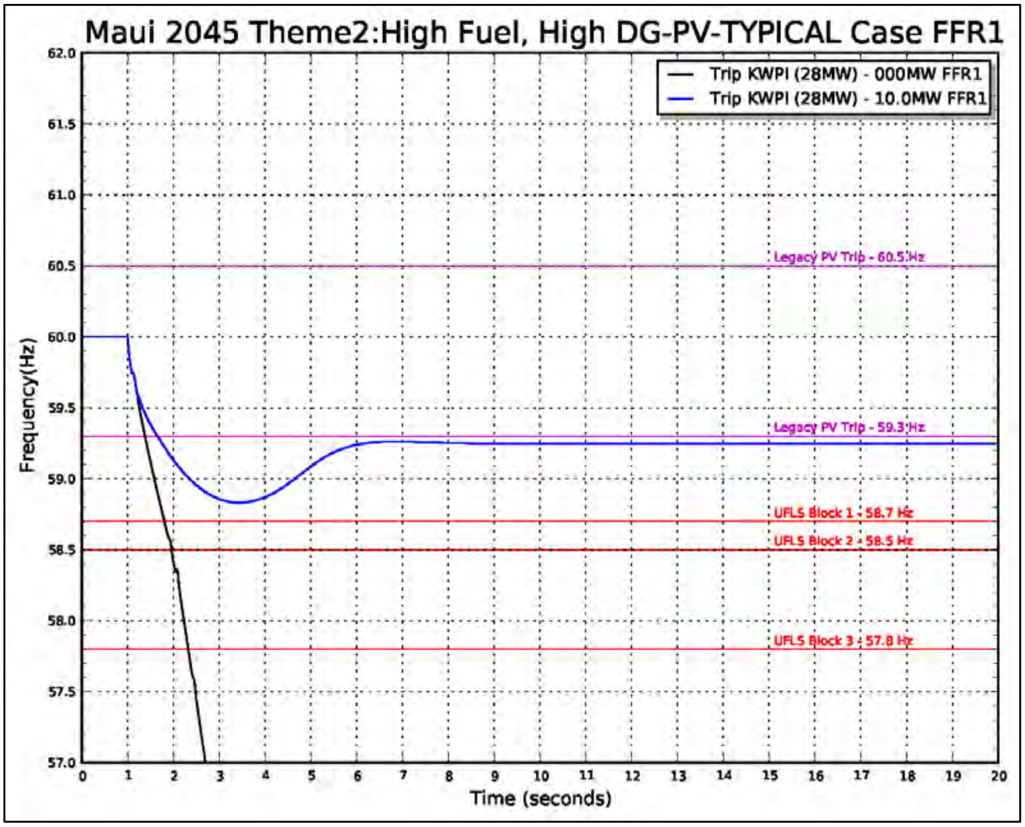


Figure O-84. Frequency Response Profile for FFR1 Typical Hour

Figure O-84 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 10 MW.

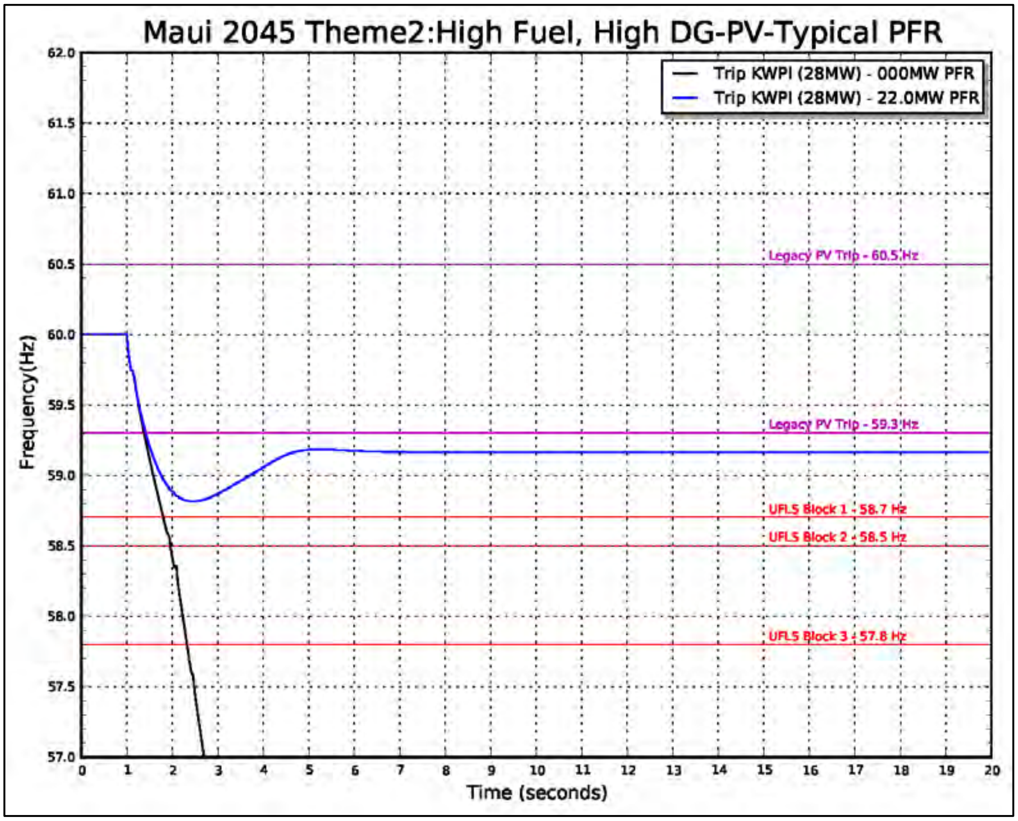


Figure O-85. Frequency Response Profile for PFR Typical Hour

Figure O-85 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 22 MW.

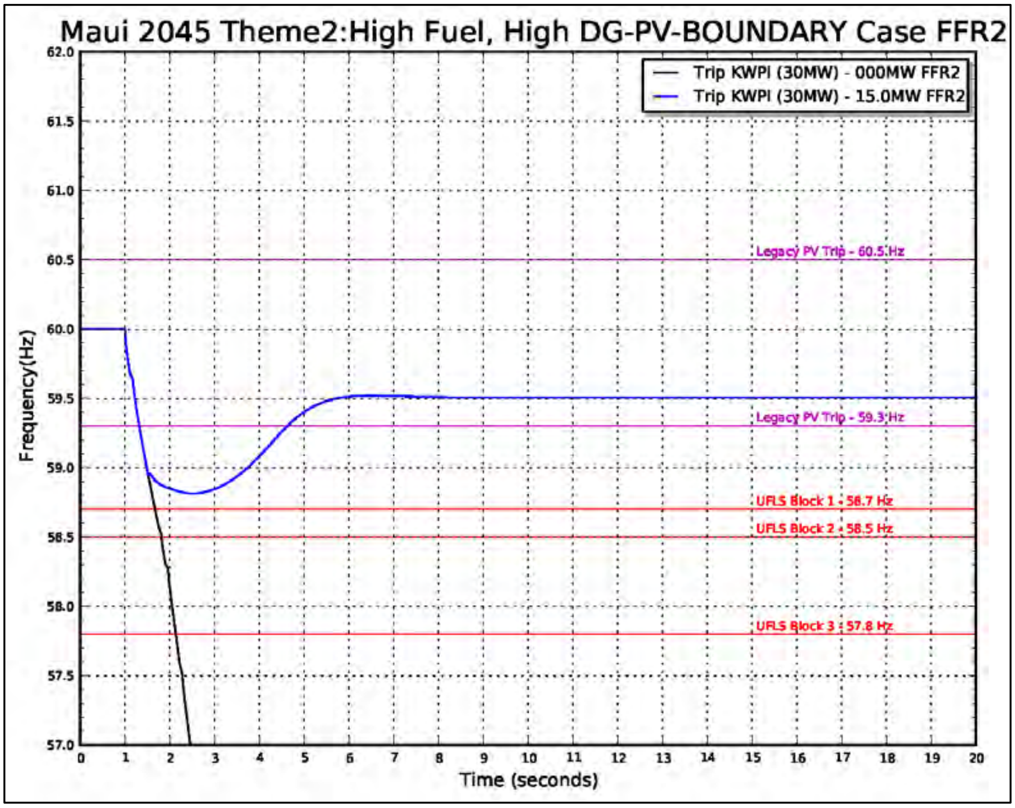


Figure O-86. Frequency Response Profile for FFR2 Boundary Hour

Figure O-86 shows the frequency response profile for a KPW wind plan trip at 30 MW output for a boundary hour. System kinetic energy is 382 MW-sec. With no FFR, the system will not survive a KWP II trip. The total capacity of Grid Supply DG-PV is 96 MW so the first block of UFLS is actually a loss of generation so the UFLS has a cascading effect on declining frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 15 MW.

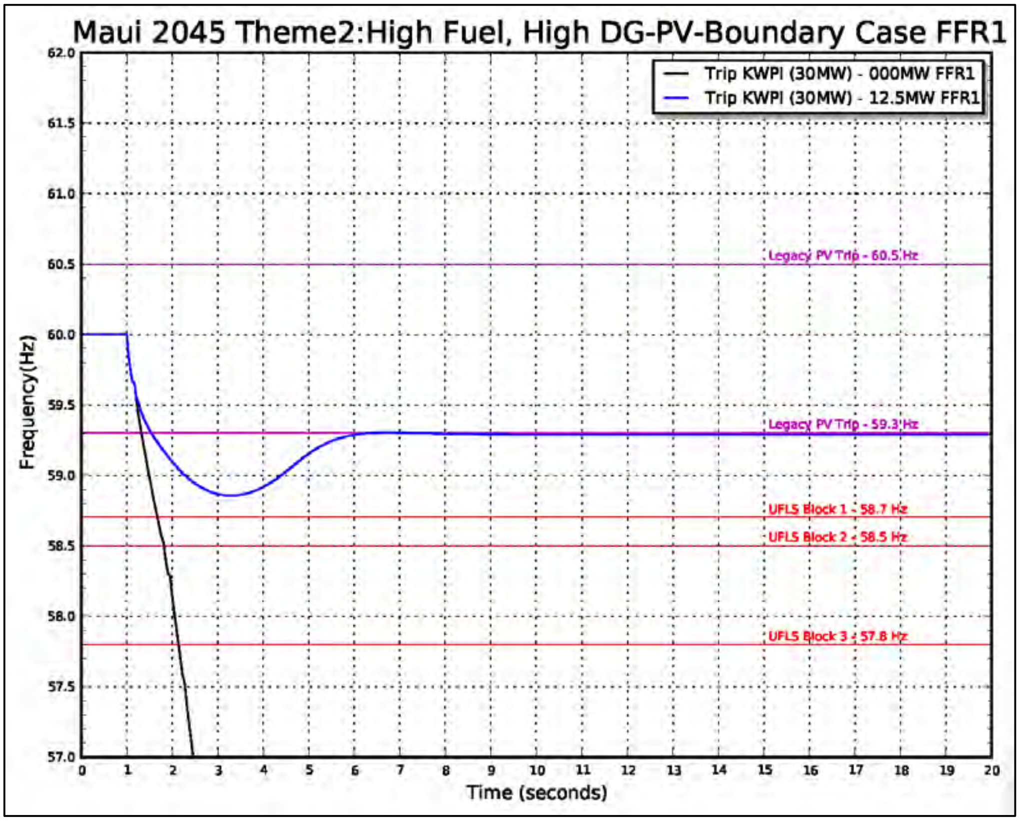


Figure O-87. Frequency Response Profile for FFR1 Boundary Hour

Figure O-87 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 12.5 MW.

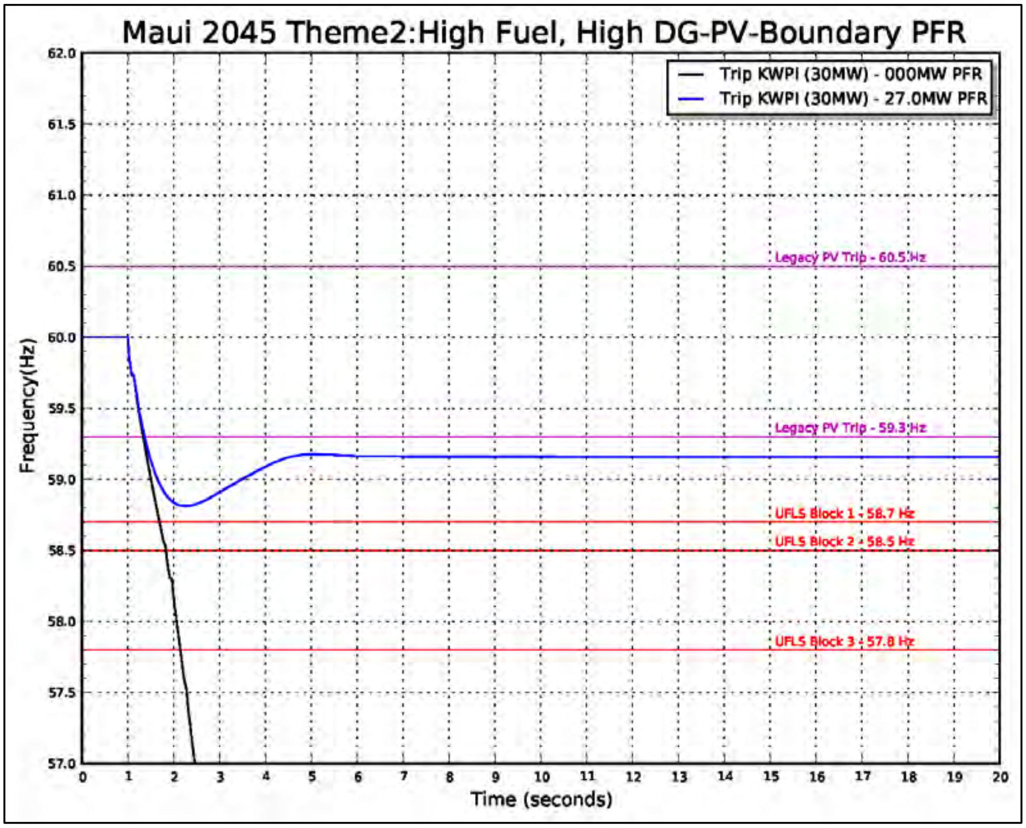


Figure O-88. Frequency Response Profile for PFR Boundary Hour

Figure O-88 shows the frequency response profile for the PFR analysis for a boundary hour. The capacity of PFR required to bring the system to avoid UFLS Block 1 and brings the system into compliance with TPL-001 is 27 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations did not produce any system security issues.

2045 69 kV and 23 kV Fault Delayed ClearingAnalysis			
Circuit Outage	**3-phase Fault Near**	**Typical Hour Condition**	**Boundary Hour Condition**
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Unstable	Unstable
	Kahului	Stable	Stable
Kahului-FDR2	FDR2	Unstable	Unstable
	Kahului	Stable	Stable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-31. Summary of Results for the 2045 Fault Analysis

Table O-31 summarizes the results of the fault analysis. For each hour, 2 simulations resulted in unstable operation. Further analysis is required to determine mitigation alternatives.

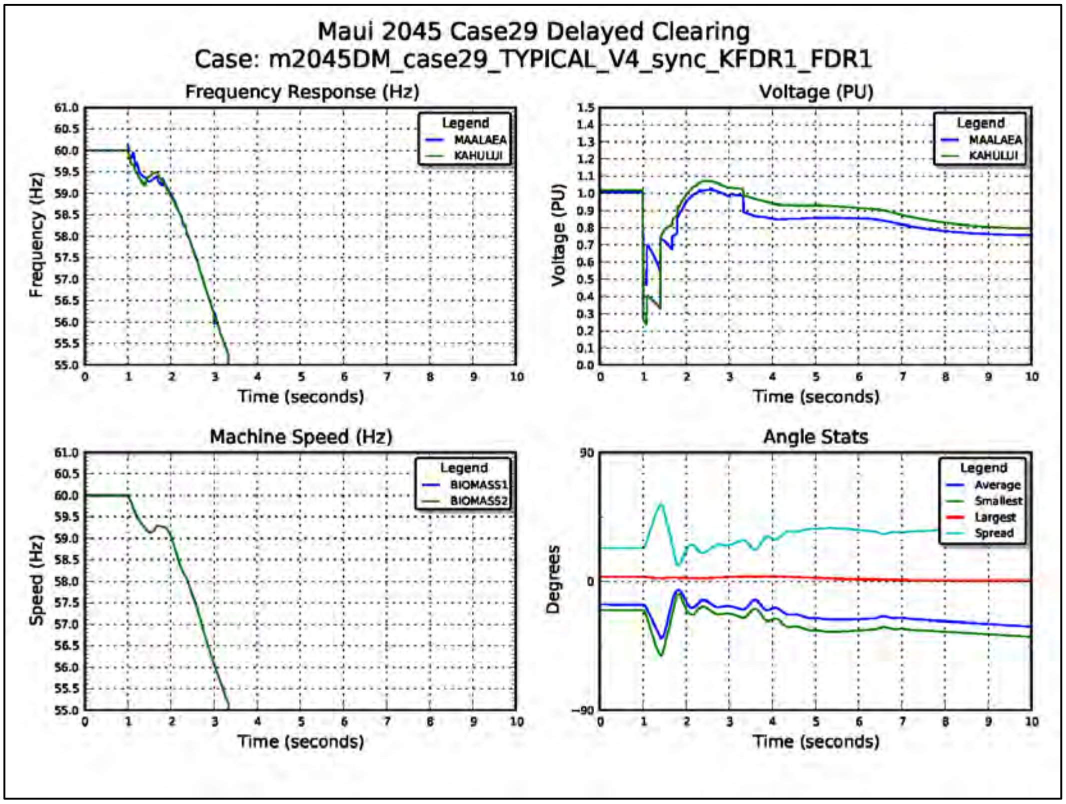


Figure O-89. System Performance for a Delayed Clearing 23 kV Fault

Figure O-89 shows four plots that illustrate system instability for a delayed clearing fault on the Kahului 23 kV circuit for the typical hour. The system frequency plot shows system will collapse. In addition to the two biomass units, KWP I and KWP II trip offline for a total of 64 MW. More analysis is required to determine mitigation alternatives.

Theme 3 – No LNG Plan

2045

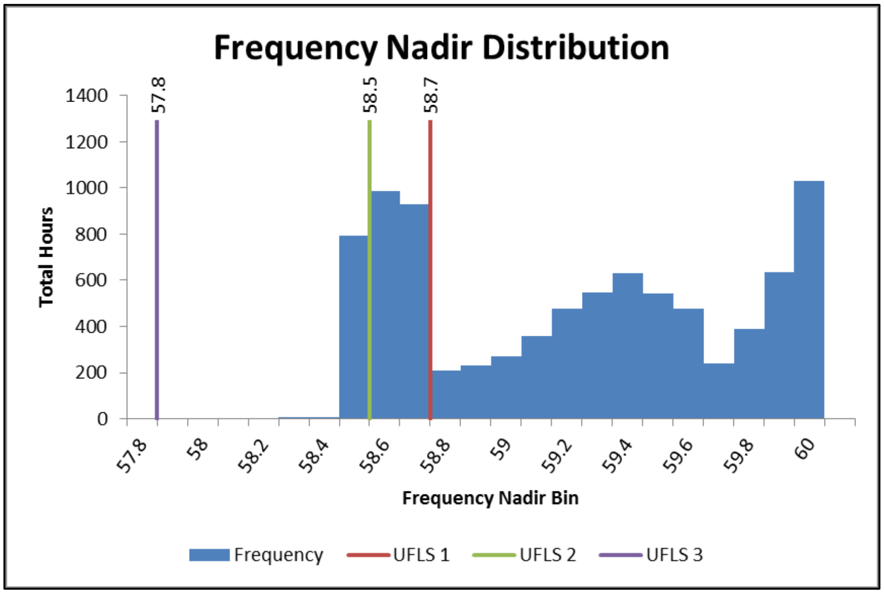


Figure O-90. Frequency Nadir Histogram for 2045

Figure O-90 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 791 hours was 11:00 AM on Monday, May 15. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 5 hours was 3:00 PM on Sunday, March 19. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires 2 blocks of UFLS to stabilize system frequency.

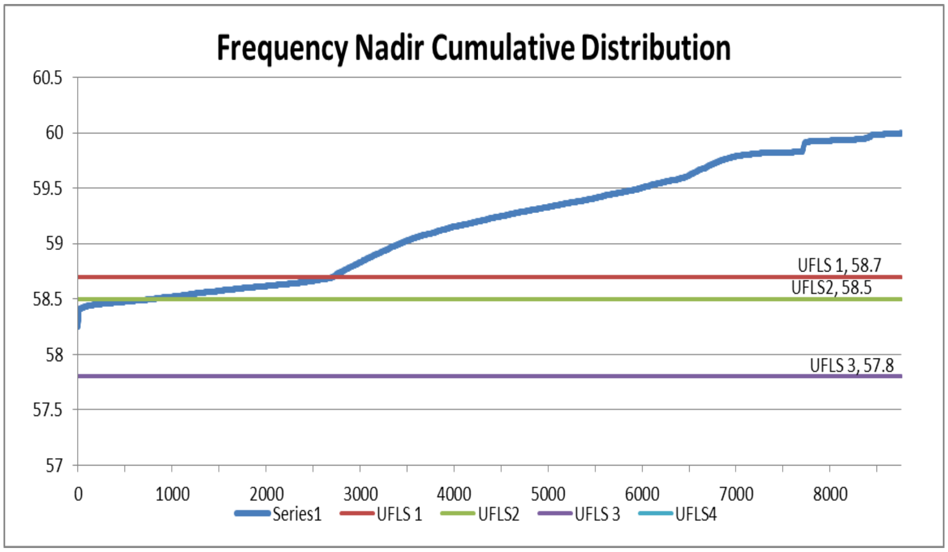


Figure O-91. Frequency Nadir Duration Curve for 2045

Figure O-91 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings					Maui 2045 (Typical) Tues 4/13/2045 Hour14			Maui 2045 (Boundary) Sun 3/19/2045 Hour15		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
M14	20.0	5.9	2.02	28.8	58						
M15	13.0	6.0	2.46	18.5	46						
M16	20.0	5.9	2.02	26.8	54						
M17	19.5	5.9	2.02	26.8	54						
M18	12.8	3.0	2.46	18.5	46						
M19	19.5	5.9	2.02	26.8	54						
Maalae10	12.3	7.9	3.28	15.6	51						
Maalae12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalae11	12.3	7.9	3.28	15.6	51						
Maalaea4	5.5	1.9	2.28	7.0	16						
Maalaea6	5.5	1.9	2.28	7.0	16						
Maalaea9	5.5	1.9	2.28	7.0	16						
Maalaea8	5.5	1.9	2.28	7.0	16						
Maalaea5	5.5	1.9	2.28	7.0	16						
Maalaea1	2.5	2.5	0.83	3.4	3						
Maalaea3	2.5	2.5	0.83	3.4	3						
Maalaea2	2.5	2.5	0.83	3.4	3						
MaalaeX2	2.5	2.5	0.83	3.4	3						
MaalaeX1	2.5	2.5	0.83	3.4	3						
Maalaea7	5.5	1.9	2.28	7.0	16						
ICE9_1	9.0	4.0	3.28	11.3	37						
ICE9_2	9.0	4.0	3.28	11.3	37						
Biomass1	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Biomass2	20.0		3.48	25.0	87	8.0	12.0	8.0	8.0	12.0	8.0
Kahului 1	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 2	0.0	0.0	2.62	6.3	16	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 3	0.0	0.0	3.27	13.5	44	0.0	Sync. Condenser		0.0	Sync. Condenser	
Kahului 4	0.0	0.0	1.74	15.6	27	0.0	Sync. Condenser		0.0	Sync. Condenser	
SYNC COND	0.0	0.0	1.74	60.0	104	0.0	Sync. Condenser		0.0	Sync. Condenser	
Total Wind	252	0				59			52		
-KWP	30	0				28			30		
-Auwahi	21	0				11			3		
-KWPII	21	0				20			19		
-New Wind 1	90	0									
-New Wind 2	90	0									
DG-PV	98.96	0				84			87		
DER Grid Ex	328	0				114			96		
Total System MVA							50			50	
Total Kinetic Energy							382			382	
Total Load							235			215	
Total Thermal Generation							16			16	
Total Renewable Generation							257			235	
Total Generation							273			251	
Excess Generation							38			36	
Regulation Requirement[1]							0			0	
Total Up Regulation							24			24	
Total Down Regulation							16			16	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-32. Unit Commitment and Dispatch Schedule 2045

Table O-32 shows the unit commitment and dispatch schedules for the typical hour (5/15/2045 at 11:00 AM) and boundary hour (3/19/2045 at 3:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

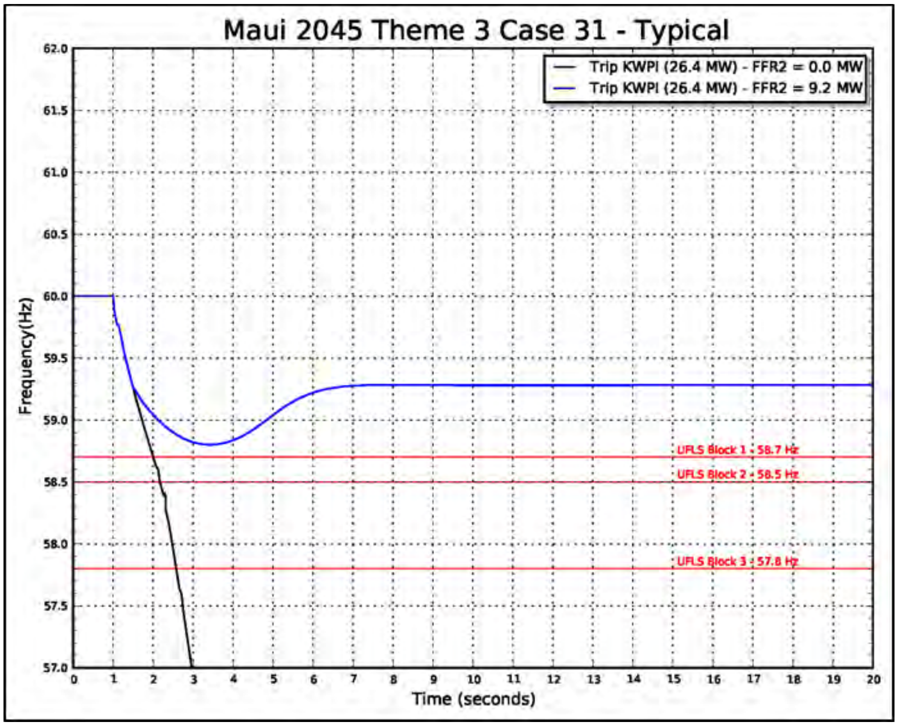


Figure O-92. Frequency Response Profile for FFR2 Typical Hour

Figure O-92 shows the frequency response profile for a KWP trip at 26.4 MW output for a typical hour. System kinetic energy is 305 MW-sec. With no FFR2, the system will not survive a KWP trip. The capacity of Grid Export DG-PV is 98.6 MW so the first block of UFLS constitutes a second loss of generation contingency. The entire UFLS scheme has a cascading effect on declining frequency with each UFLS block exacerbating the contingency until system collapse. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9.2 MW.

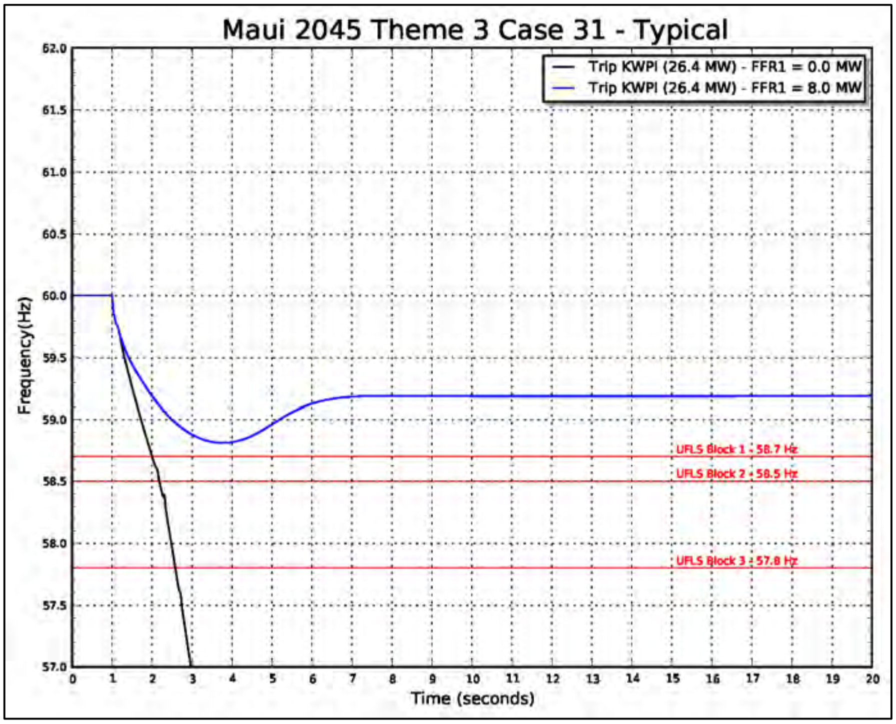


Figure O-93. Frequency Response Profile for FFR1 Typical Hour

Figure O-93 shows the frequency response profile for the FFR1 analysis for a typical hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

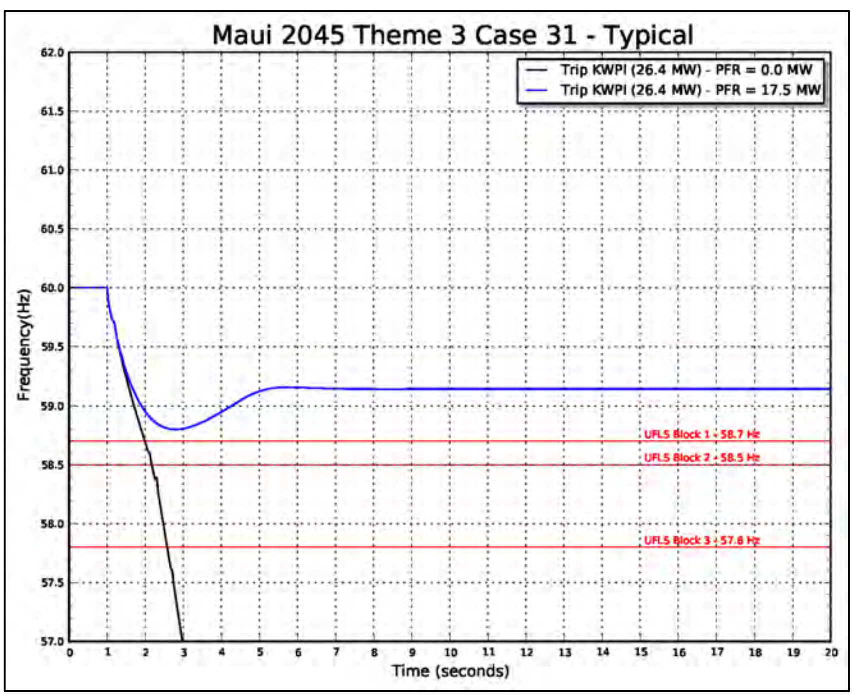


Figure O-94. Frequency Response Profile for PFR Typical Hour

Figure O-94 shows the frequency response profile for the PFR analysis for a typical hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 17.5 MW.

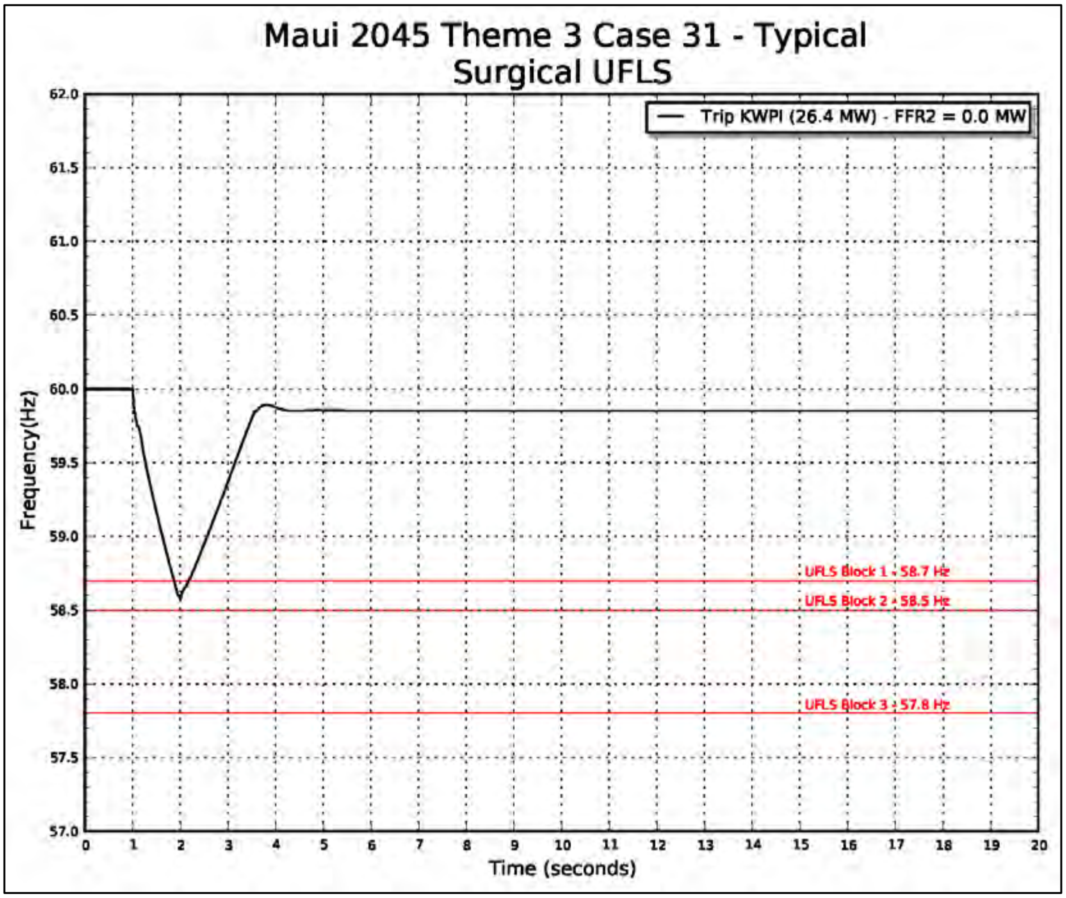


Figure O-95. Frequency Response Profile for Behind-the-Meter Load Shedding

Figure O-95 shows the frequency response profile if behind the meter load shedding was available. The frequency nadir is 58.6 Hz and meets the requirements of TPL-001 without FFR.

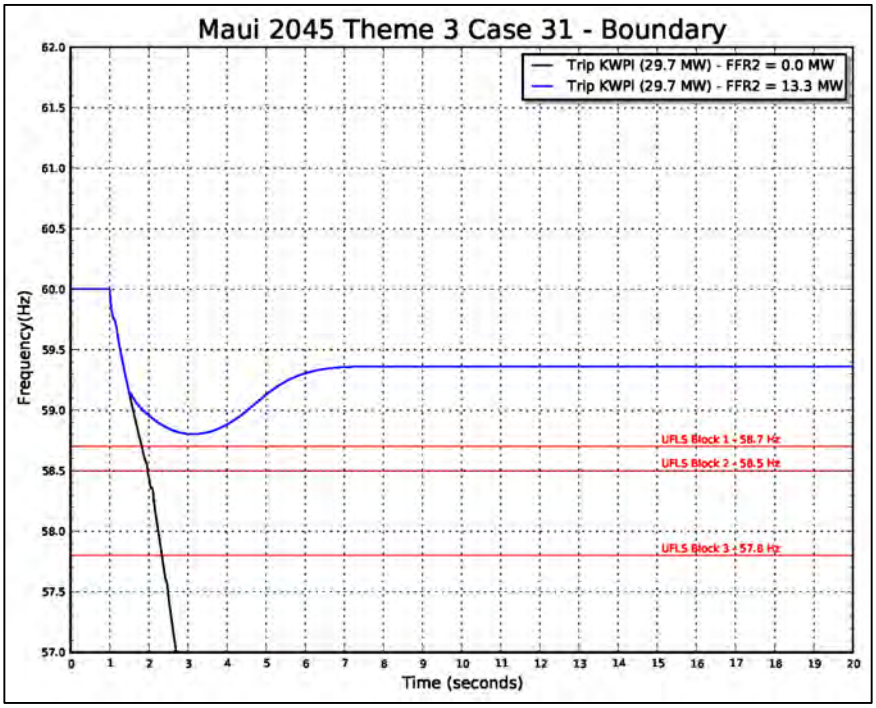


Figure O-96. Frequency Response Profile for FFR2 Boundary Hour

Figure O-96 shows the frequency response profile for a KWP trip at 29.7 MW output for a boundary hour. System kinetic energy is 305 MW-sec. With no FFR2, the system will not survive a biomass unit trip. The capacity of Grid Export DG-PV is 98.2 MW so the first block of UFLS constitutes a second loss of generation contingency. The entire UFLS scheme has a cascading effect on declining frequency with each UFLS block exacerbating the contingency until system collapse. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13.3 MW.

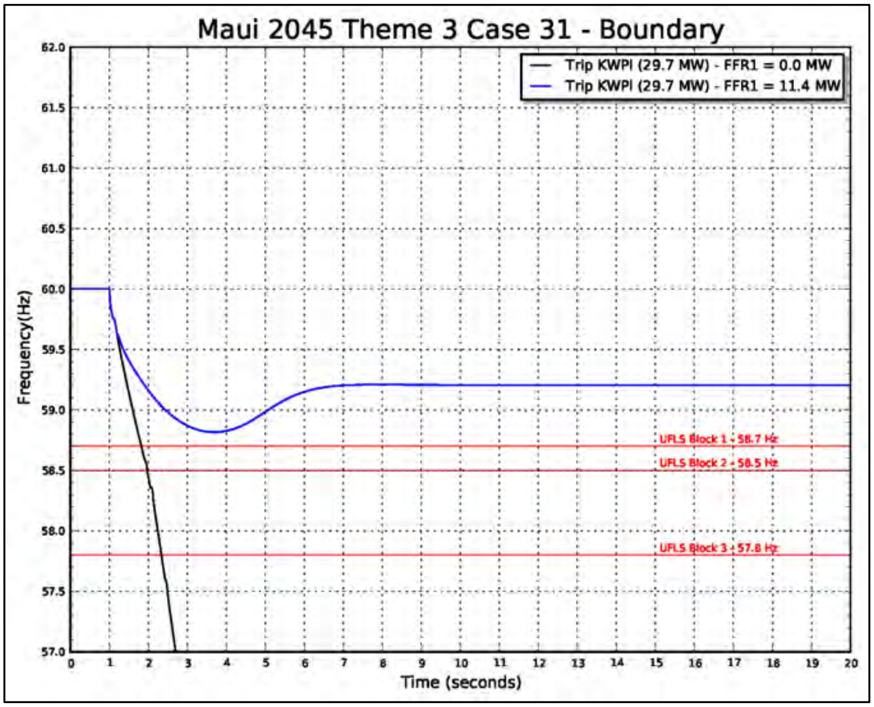


Figure O-97. Frequency Response Profile for FFR1 Boundary Hour

Figure O-97 shows the frequency response profile for the FFR1 analysis for a boundary hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 11.4 MW.

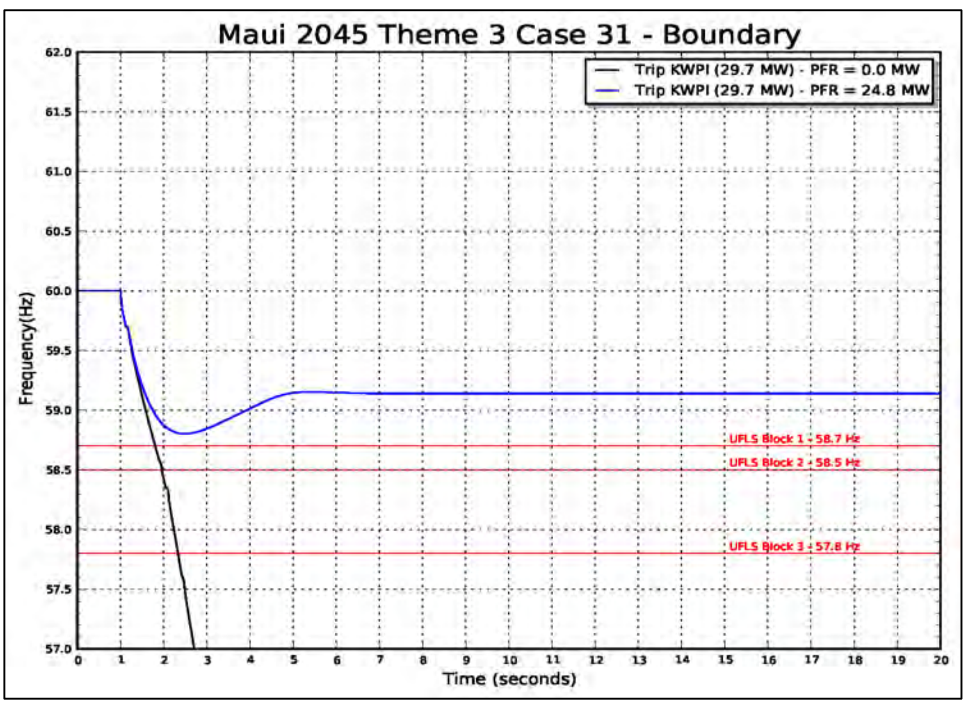


Figure O-98. Frequency Response Profile for PFR Boundary Hour

Figure O-98 shows the frequency response profile for the PFR analysis for a boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 24.8 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations for the normally cleared faults did not produce any significant system security issues. Simulations for the 69kV fault analysis did not produce any significant system security issues.

2045 69 kV and 23 kV Fault Delayed Clearing Analysis			
Circuit Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
Maalaea-Kihei	Kihei	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Waiinu	Waiinu	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Puunene	Puunene	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP I	KWP I	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-KWP II	KWP II	Stable	Stable
	Maalaea	Stable	Stable
Maalaea-Lahainaluna	Lahainaluna	Stable	Stable
	Maalaea	Stable	Stable
Kahului-FDR1	FDR1	Unstable	Unstable
	Kahului	Unstable	Unstable
Kahului-FDR2	FDR2	Unstable	Unstable
	Kahului	Unstable	Unstable
Kahului-Wailuku	Wailuku	Stable	Stable
	Kahului	Stable	Stable

Table O-33. Summary of Resulsts Delayed Clearing Fault Analysis 2045

Table O-33 summarizes the results of the fault analysis. For each hour, 4 simulations resulted in unstable operation. Further analysis is required to determine mitigation alternatives.

Summary

The Maui system does not meet the requirements of TPL-001. Simulations were performed to determine the capacity of FFR2 and FFR1 required to the system into compliance with TPL-001 in 2019.

Compliance with TPL-001

The capacities of frequency response reserves required to bring Maui into compliance with TPL-001 are listing in Table O-34 below.

Maui Frequency Response Analysis Results								
Freq Response	Theme 2						Theme 3	
	2019		2023		2045		2045	
	Typical KWP 28 MW	Boundary KWP 30 MW	Typical KWP 23 MW	Boundary KWP 29 MW	Typical KWP 28 MW	Boundary KWP 30 MW	Typical KWP 26.4 MW	Boundary KWP 30 MW
FFR2	4	13	6.5	15.5	12	15	9.2	13.3
FFR1	3.5	11	5.5	13.5	10	12.5	8	11.4
PFR	7.5	21.5	11	25	22	27	17.5	24.8

Table O-34. Summary of Frequency Response Analysis

Table O-34 shows the results of the FFR2, FFR1, and PFR analysis. The capacities of FFR1 required to meet TPL-001 is 3.5 MW for the typical hour and 11 MW for the boundary hour. These capacities of will not bring the resource plans for Themes 2 and 3 into compliance with TPL-001 through 2045 without additional resources from FFR2, PFR, or more system inertia.

HAWAII ELECTRIC LIGHT CANDIDATE PLANS

State of the System

The Hawaiʻi Electric Light (HELCO) system does not meet standard HI-TPL-001 for loss of generation contingency events so FFR analysis are performed for 2019.

Hawai'i Electric Light has the highest penetration of renewable resources in the nation and the system often operates with the minimum must-run units for system security. In addition to the frequency stability issues that face O'ahu and Maui, characteristics of the Hawaiʻi Electric Light transmission system increase the exposure to electrical faults. The Hawai'i transmission system covers a very large territory and has approximately 640 miles of 69 kV transmission lines. In addition, Hawaiʻi Electric Light 's transmission planning criteria is N-1 because of the potential rate impacts for cost recovery from a smaller customer base which is similar to Maui Electric. The Hawai'i Electric Light transmission system is also more susceptible to steady state and transient voltage stability issues.

Date/Time	Line	Type of Fault	Lowest Voltages at Keahole (A / B /C phase)	Load Loss (MW)	Frequency Peak
Sun 8/23/15 0055 hrs	7500/9300	2-Line-Gnd	0.28pu / 0.26pu / 0.79pu	17	60.68
Sun 8/23/15 1455 hrs	8100/8200	3-phase	0.44pu / 0.46pu / 0.42pu	17	60.41
Sun 8/23/15 1502 hrs	6800	3-phase	0.43pu / 0.43pu / 0.45pu	10	60.2
Sun 8/23/15 1541 hrs	6200	3-phase	0.45pu/ 0.45pu / 0.45pu	14	60.28
Wed 9/2/15 1605 hrs	7100	3-phase	0.33pu / 0.37pu / 0.34pu	20	60.43
Thu 9/3/15 1454 hrs	8100/8200	3-phase	0.41pu / 0.43pu / 0.41pu	18	60.41
Sun 9/13/15 1541 hrs	7100	A-Gnd	0.61pu / 0.86pu / 0.61pu	5	60.17
Sun 9/13/15 1641 hrs	7100	3-phase	0.28pu / 0.30pu / 0.28pu	17	60.32
Tue 9/15/15 1733hrs	7500/9300	A-Gnd	0.26pu / 0.68pu / 0.66pu	20	60.5

Table O-35. Hawai'i Electric Light Historic Transmission Faults

Table O-35 shows some of the more severe electrical faults on the 69 kV transmission system that illustrates the increase exposure to multi-phase electrical faults that can trigger loss of load. Therefore, fault simulations will be included in the analysis to bring the system into compliance with TPL-001.

Hawai'i relies on under frequency load shedding for frequency response reserves for N-1 loss of generation contingency events. Hawai'i Electric Light has implemented a dynamic UFLS scheme to meet the requirements specified in TPL-001 that allows 15% of the system load to be shed on single loss of generation contingency events.

	Setpoint (Hz)	df/dt	% System Net Demand
Block 1	59.1	0.5 Hz/sec	5%
Block 2	58.8	0.5 Hz/sec	10%
Block 3	58.5	N/A	10%
Block 4	58.2	N/A	15%
Block 5	57.9	N/A	10%
Block 6	57.6	N/A	20%
Kicker Block (>9 sec TD)	59.3	N/A	5 MW

Table O-36. Hawai'i Electric Light Dynamic UFLS

Table O-36 shows the capacities of the UFLS scheme. The dynamic UFLS scheme allows Blocks 1 and 2 to be initiated on df/dt settings for severe loss of generation contingency events; or by frequency set points for less severe contingencies but in most instances, the df/dt relays are activated. The dynamic UFLS scheme continuously monitors distribution circuit loads such that Blocks 1 and 2 will meet the 15% load shed requirement established by TPL-001.

Historical

2016

System security analysis was performed on multiple hours that were selected from the Theme 3 production cost simulations that represents a typical hour, a boundary condition, and for some cases, an alternate hour to evaluate the impacts of high DG-PV penetration.

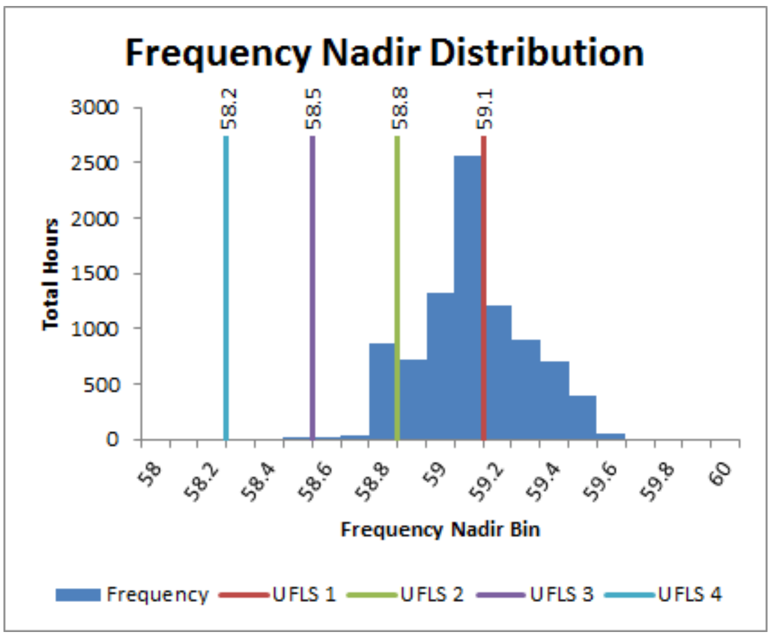


Figure O-99. Frequency Nadir Histogram for 2016

Figure O-99 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 869 hours was 12:00 PM on Thursday, March 3. The frequency nadir range for the typical hour is 58.7 – 58.8 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour was selected from a minimum distribution of 1 hour was 5:00 AM on Sunday, July 10. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

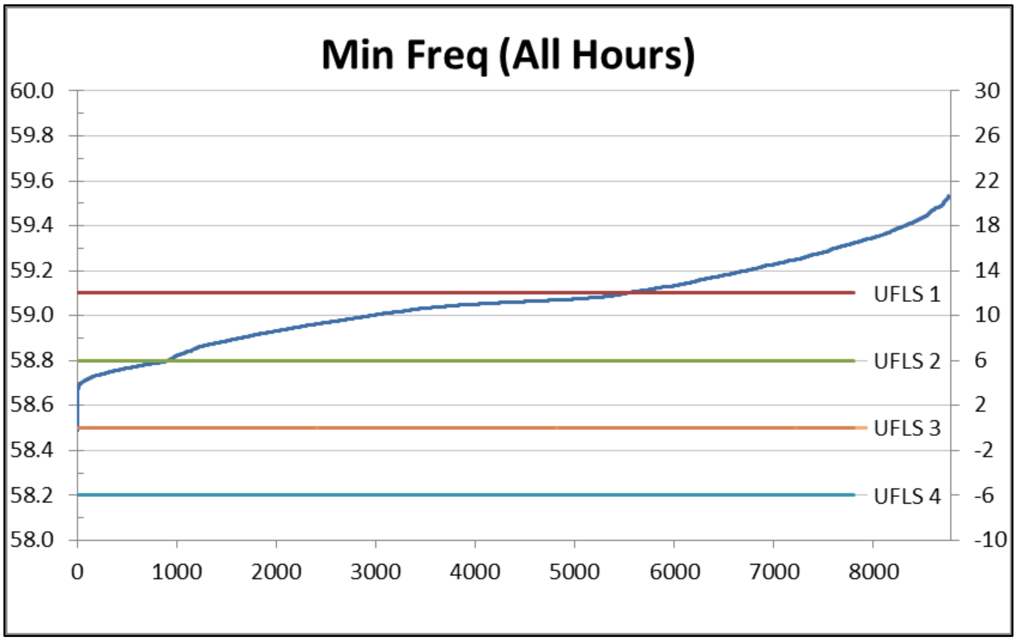


Figure O-100. Frequency Nadir Duration Curve 2016

Figure O-100 shows the frequency nadir duration curve for 2016.

Unit Commitment Order	Unit Ratings							HELCO 2016 (Typical) Thu 3/3/16 Hour 12			HELCO 2016 (Boundary) Sun 7/10/16 Hour 5			HELCO 2016 (Alt) Sun 9/4/16 Hour 12		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	30.3	7.7	8.3	33.4	4.6	11.4	32.9	5.1	10.9
Keahole STCC	25.0	7.0			3.13	46.5	146	24.5	0.5	17.5	22.0	3.0	15.0	20.3	4.7	13.3
Keahole DTCC	54.0	7.0			2.77	71.8	199									
Keahole CT4	20.0	7.0			2.10	25.2	53									
Keahole CT5	20.0	7.0			2.10	25.2	53									
HEP STCC	28.5	9.0			1.96	58.9	116	14.1	14.4	5.1						
HEP DTCC	60.0	18.5			1.78	94.4	168									
Hill 5	13.5	5.0			2.20	15.6	34	8.2	5.3	3.2	11.6	1.9	6.6			
Hill 6	20.5	8.0			2.53	27.5	70	11.6	8.9	3.6	19.7	0.8	11.7	11.4	9.1	3.4
Keah CT2	13.8	5.0			4.44	22.2	99									
Puna CT3	20.0	7.0			4.96	29.6	147									
Geo1	20.0				5.00	40.0	200									
Geo2	20.0				5.00	40.0	200									
Biomass1	20.0				3.16	28.0	88									
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.8			2.7			1.8		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	2.9			0.7			7.7		
Apollo	20.5	0.0						4.9			3.8			17.9		
HRD	10.5	0.0						0.0			1.9			4.1		
Hydro	16.8	0						6			3			10		
Wind	31.0	0						5			6			22		
DG-PV	88.4	0						65			0			56		
Total Kinetic Energy									576			460			426	
Total Load									164			96			152	
Total Thermal Generation									89			87			65	
Total Renewable Generation									75			9			87	
Total Generation									164			96			152	
Excess Generation									0			0			0	
Total Up Regulation									37			10			19	
Total Down Regulation									38			45			28	
Legacy DG-PV	59.3Hz Capacity		7.4					59.3Hz Output		5.4	59.3Hz Output		0.0	59.3Hz Output		4.7
	60.5Hz Capacity		26.4					60.5Hz Output		19.3	60.5Hz Output		0.0	60.5Hz Output		16.7

Table O-37. Unit Commitment and Dispatch 2016

Table O-37 shows the unit commitment and dispatch schedules for the typical hour (3/3/2016 at 12:00 PM), boundary hour (7/10/2016 at 5:00 AM), and an alternate hour (9/4/2016 AT 12:00 pm).

Loss of Generation Contingency

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

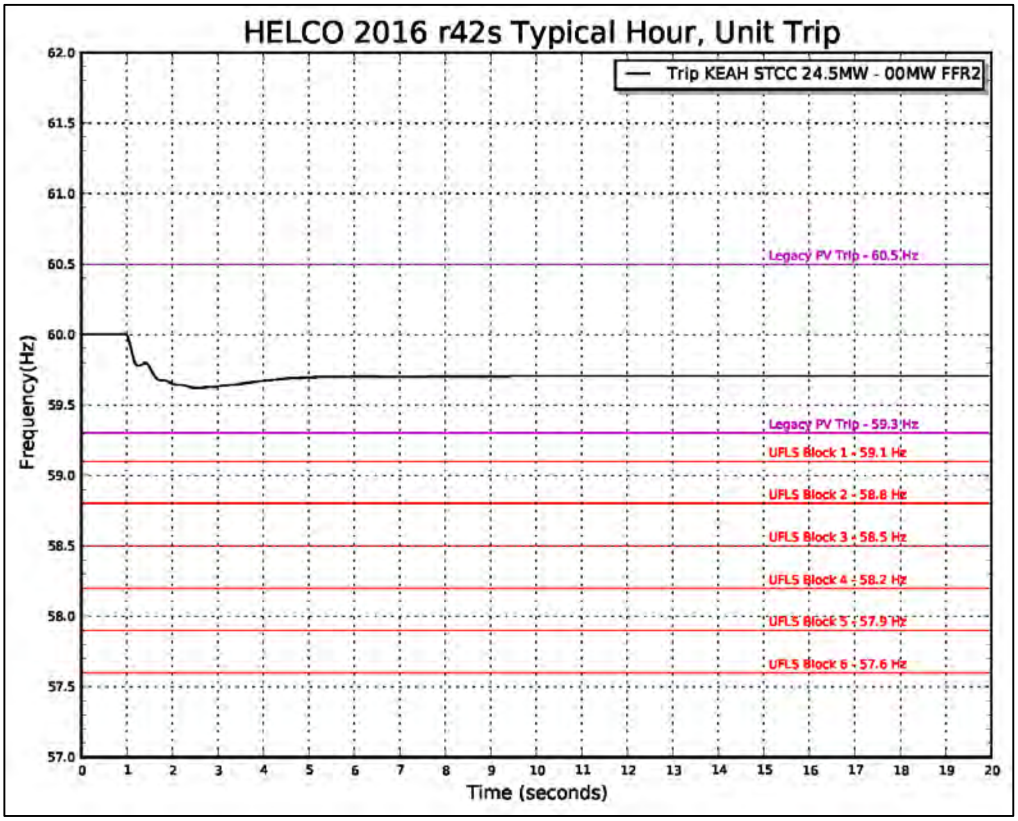


Figure O-101. Frequency Response Profile FFR2 Typical Hour

Figure O-101 shows the frequency response profile for a Keahole STCC trip at 24.5 MW output. System kinetic energy is 576 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.4 MW. No FFR2 is required because Hawai‘i Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The capacity of df/dt UFLS was 24.6 MW which is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

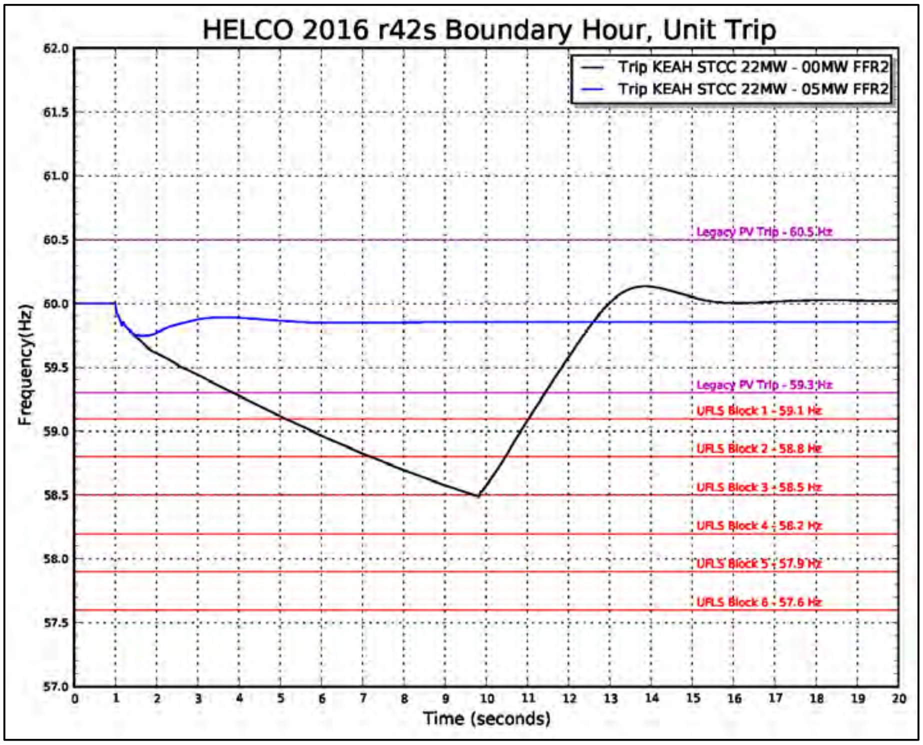


Figure O-102. Frequency Response Profile FFR2 Boundary Hour

Figure O-102 shows the frequency response profile for a Keahole STCC trip at 22 MW output for the boundary hour. System kinetic energy is 460 MW-sec. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW. This is in addition to the 14.4 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. A three-phase fault was placed on a transmission line to evaluate system performance to normally cleared faults and delayed clearing faults. Normally cleared faults are isolated in 5-cycles and delayed clearing faults are isolate in 24 cycles to simulate Zone 2 clearing. Simulations for the normally cleared faults did not produce any system stability issues.

2016 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Stable
	Kaumana	Unstable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Unstable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Unstable	Unstable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Unstable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Unstable	Unstable
L9200	Kaumana	Stable	Stable
	Wailuku	Stable	Unstable
L9300	Kailua	Unstable	Unstable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-38. Summary of Results for the Fault Analysis

Table O-38 summarizes the results of the fault analysis. For the typical hour, 8 simulations resulted in unstable operation and 9 simulations resulted in unstable operation for the boundary hour.

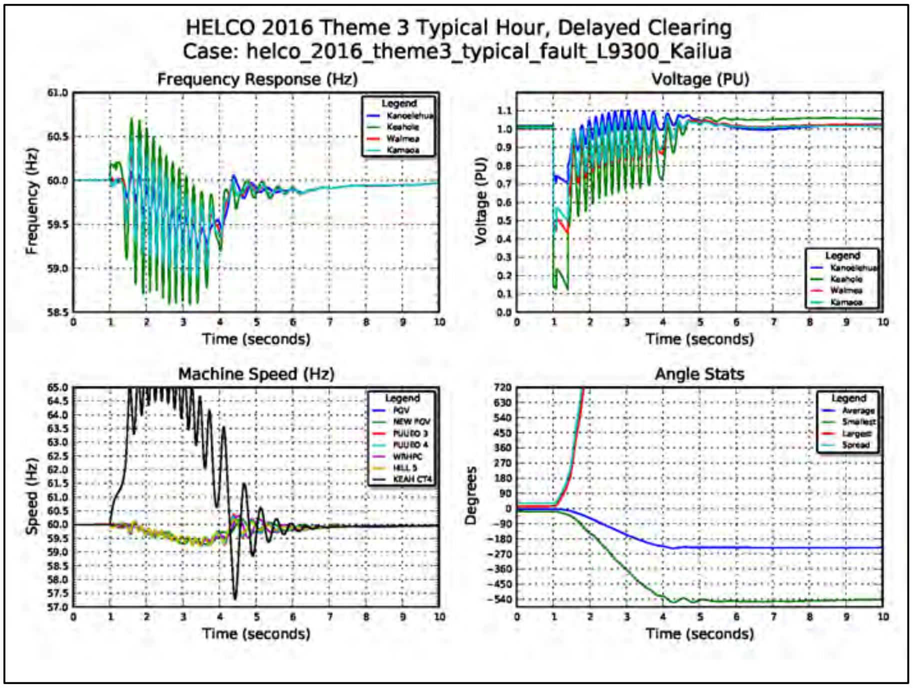


Figure O-103. System Performance for Delayed Clearing Failure Analysis

Figure O-103 shows four plots that illustrate unstable operation for a delayed clearing fault on the L9300 Kailua circuit for the typical hour. The Machine Speed plot shows Keahole CT4 (black) losing synchronism with the system. More analysis is required to determine mitigation measures.

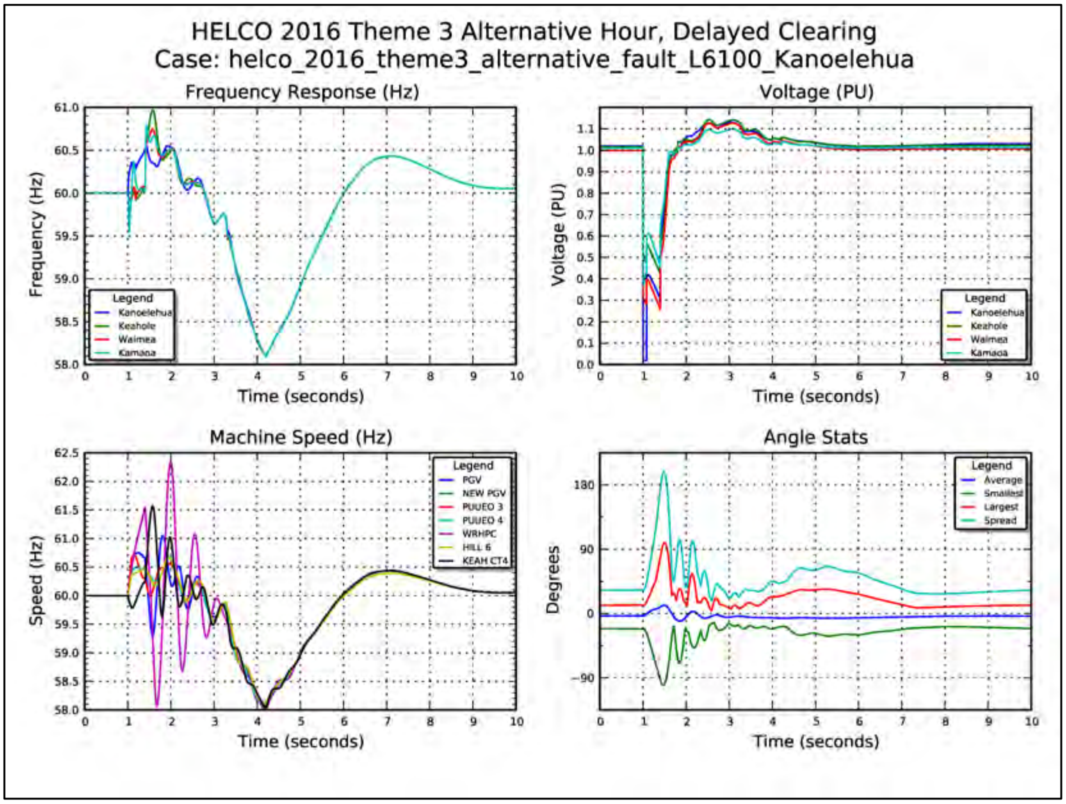


Figure O-104. System Performance Delayed Clearing Load Shed Analysis

Figure O-104 shows four plots that illustrate system performance for a delayed clearing fault on the L6100 Kanoelehua circuit for the alternative hour. System voltage exceeds 1.1 PU, tripping all 56 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

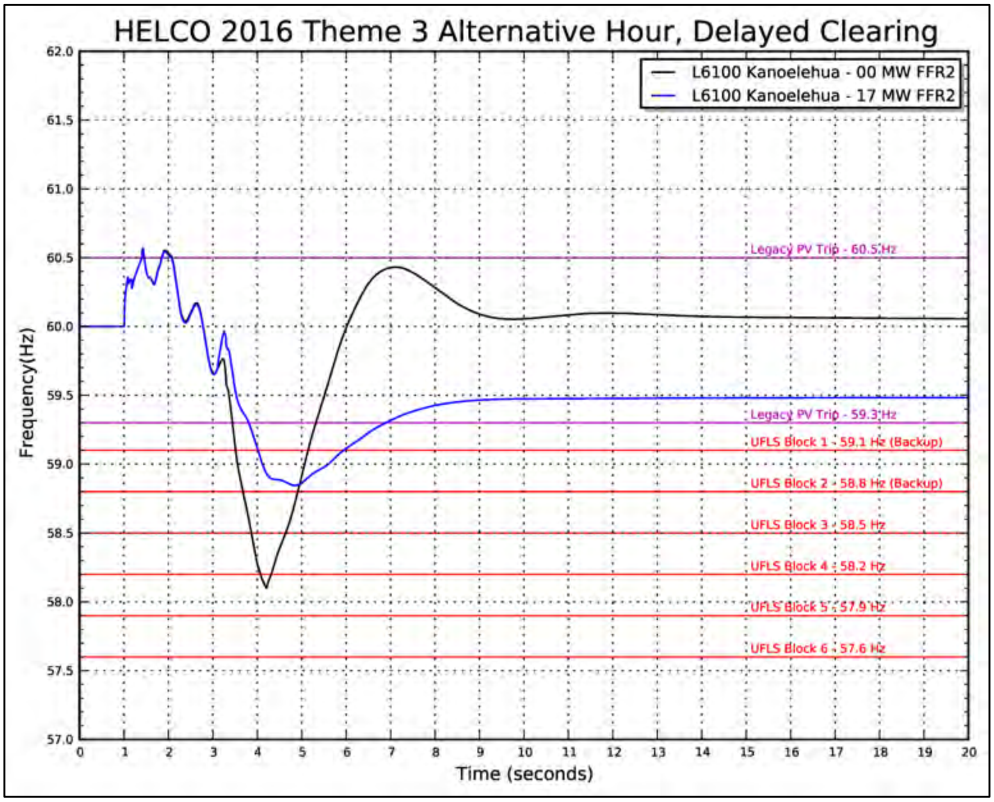


Figure O-105. Frequency Response Profile FFR2 Alternate Hour

Figure O-105 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 17 MW of legacy PV disconnects at 60.5 Hz but 56 MW of DG-PV disconnects on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (22.8 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir hits 58.1 Hz, requiring 4 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 17 MW.

2019 – Compliance with TPL-001-02

System security analysis was performed on three hours that were selected from the Theme 3 production cost simulations that represents a typical hour, a boundary condition, and an alternate hour to evaluate the impacts of high DG-PV penetration.

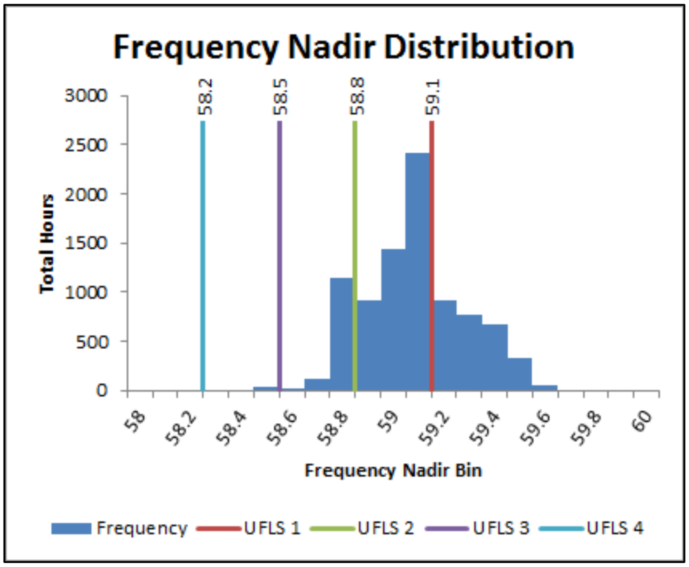


Figure O-106. Frequency Nadir Histogram 2019

Figure O-106 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1665 hours was 12:00 PM on Monday, August 19. The frequency nadir range for the typical hour is 58.0 - 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 5 hours was 1:00 PM on Saturday, January 26. The frequency nadir range for the boundary hour is 57.6 – 57.7 Hz that requires five blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

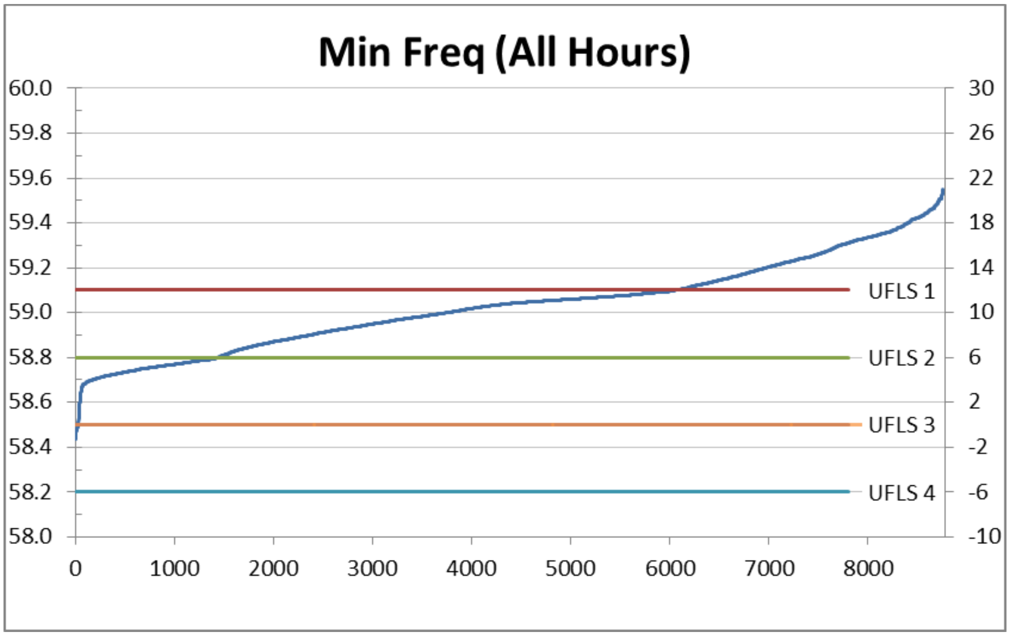


Figure O-107. Frequency Nadir Duration Curve 2019

Figure O-107 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2019 (Typical) Wed 8/14/19 Hour 10			HELCO 2019 (Boundary) Mon 6/17/19 Hour 1			HELCO 2019 (Alt) Mon 6/17/19 Hour 15		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174				35.3	2.7	13.3	35.6	2.4	13.6
Keahole STCC	25.0	7.0			3.13	46.5	146				24.5	0.5	17.5	22.0	3.0	15.0
Keahole DTCC	54.0	7.0			2.77	71.8	199	25.7	28.3	18.7						
Keahole CT4	20.0	7.0			2.10	25.2	53									
Keahole CT5	20.0	7.0			2.10	25.2	53									
HEP STCC	28.5	9.0			1.96	58.9	116	28.0	0.5	19.0						
HEP DTCC	60.0	18.5			1.78	94.4	168									
Hill 5	13.5	5.0			2.20	15.6	34	8.0	5.5	3.0	11.0	2.5	6.0	8.0	5.5	3.0
Hill 6	20.5	8.0			2.53	27.5	70	11.0	9.5	3.0						
Keah CT2	13.8	5.0			4.44	22.2	99									
Puna CT3	20.0	7.0			4.96	29.6	147									
Geo1	20.0				5.00	40.0	200									
Geo2	20.0				5.00	40.0	200									
Biomass1	20.0				3.16	28.0	88									
HELCO Hydro	4.7	0.0			1.07	5.6	6	3.1			3.6			3.6		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	8.3			2.7			5.8		
Apollo	20.5	0.0						16.6			18.1			19.3		
HRD	10.5	0.0						5.3			1.8			10.5		
Wind1	20.0	0.0														
Wind2	20.0	0.0														
Wind3	20.0	0.0														
Hydro	16.8	0						11			6			9		
Wind	31.0	0						22			20			30		
DG-PV	116.2	0						63			0			66		
Total Kinetic Energy									454			390			390	
Total Load									169			97			171	
Total Thermal Generation									73			71			66	
Total Renewable Generation									96			26			105	
Total Generation									169			97			171	
Excess Generation									0			0			0	
Total Up Regulation									44			6			11	
Total Down Regulation									44			37			32	
Legacy DG-PV	59.3Hz Capacity		7.4					59.3Hz Output		4.0	59.3Hz Output		0.0	59.3Hz Output		4.2
	60.5Hz Capacity		26.4					60.5Hz Output		14.2	60.5Hz Output		0.0	60.5Hz Output		15.0

Table O-39. Unit Commitment and Dispatch 2019

Table O-39 shows the unit commitment and dispatch for the typical hour (8/19/2019, 12:00 PM), boundary hour (6/17/2019, 1:00 AM), and alternative hour (6/17/2019, 3:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

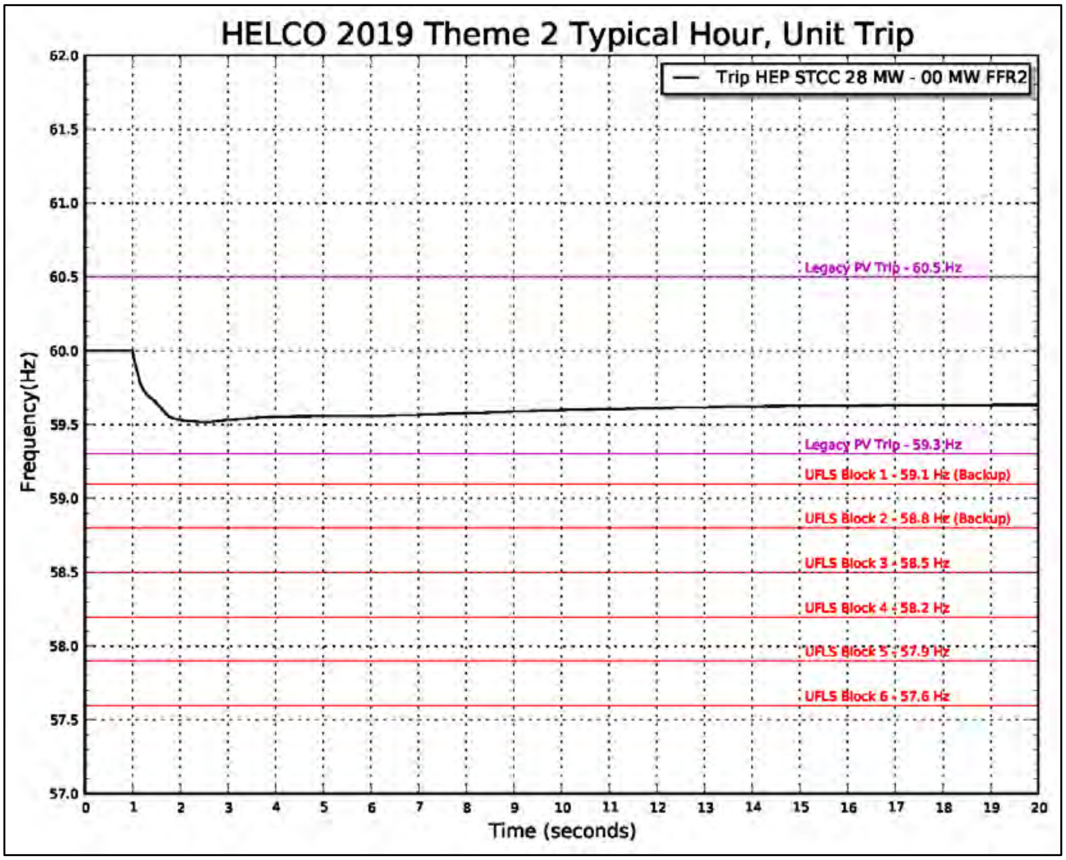


Figure O-108. Frequency Response Profile FFR2 Typical Hour

Figure O-108 shows the frequency response profile for a HEP STCC trip at 28 MW for a typical hour. System kinetic energy is 454 MW-sec and the capacity of legacy PV that will disconnect from the system is 4 MW. No FFR2 is required because Hawai'i Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 25.4 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

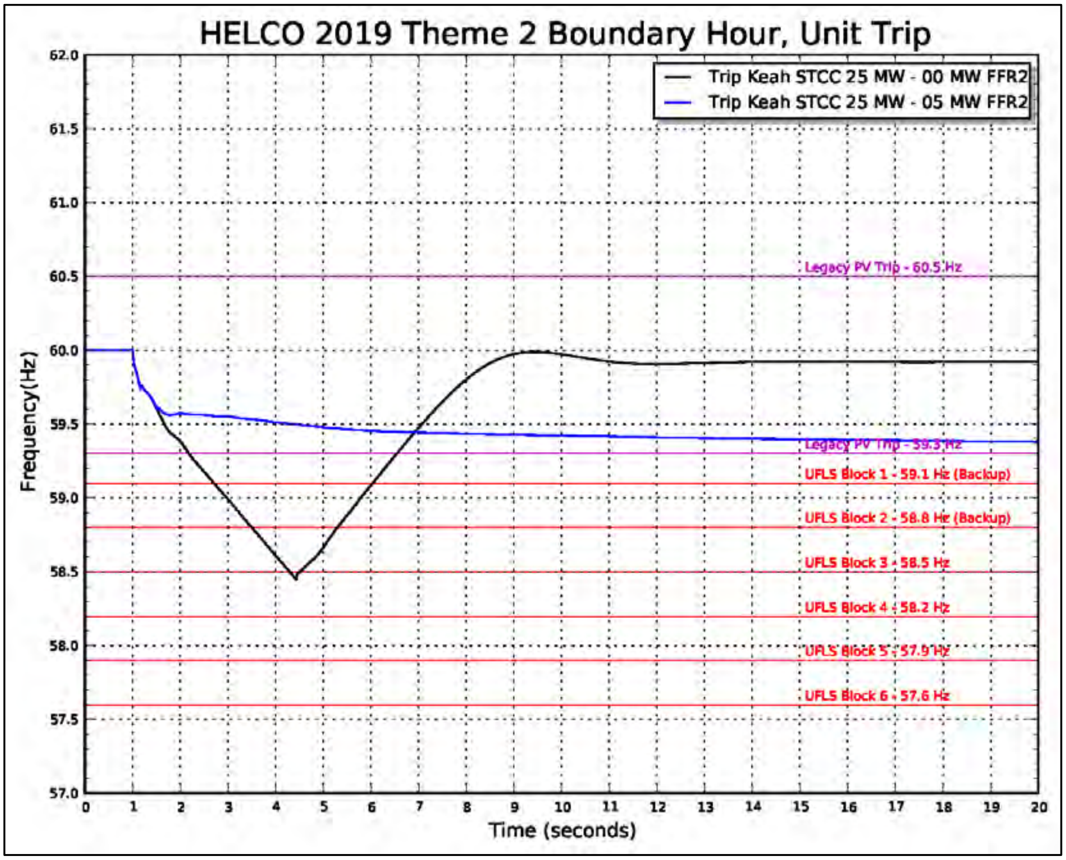


Figure O-109. Frequency Response Profile FFR2 Boundary Hour

Figure O-109 shows the frequency response profile for a Keahole STCC trip at 25 MW for a boundary hour. System kinetic energy is 390 MW-sec. With no FFR2, the frequency nadir breaches 58.5 Hz requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW. This is in addition to the 14.6 MW of df/dt UFLS from Blocks 1 and 2.

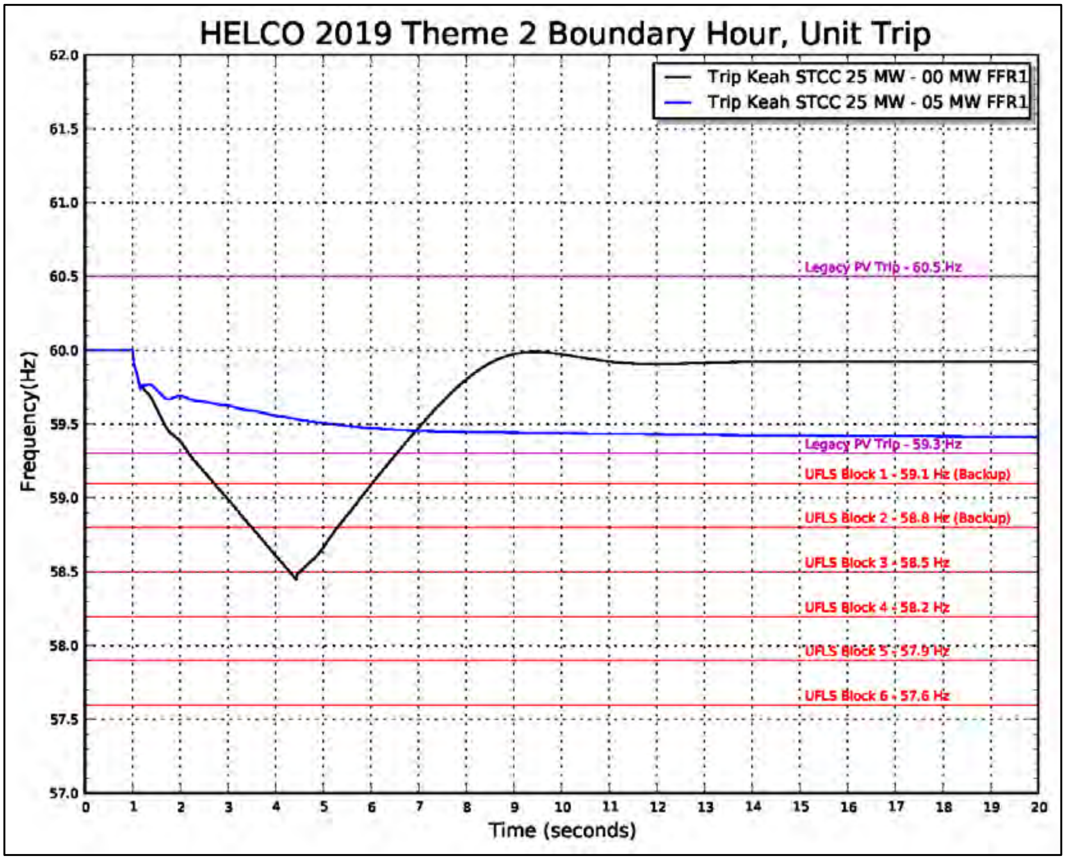


Figure O-110. Frequency Response Profile FFR1 Boundary Hour

Figure O-110 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

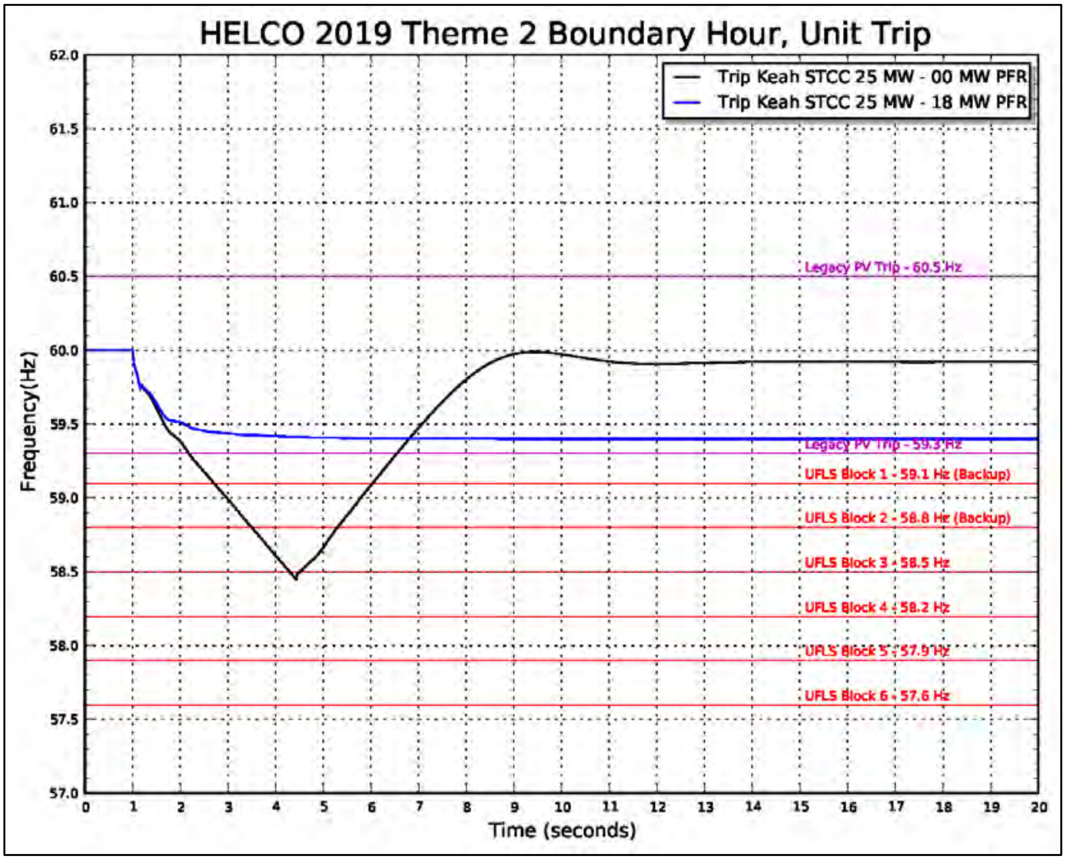


Figure O-111. Frequency Response Profile PFR Boundary Hour

Figure O-111 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 18 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2019 69 kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Unstable
	Kaumana	Unstable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Unstable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Stable	Unstable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Unstable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Unstable
L9200	Kaumana	Stable	Stable
	Wailuku	Unstable	Unstable
L9300	Kailua	Stable	Unstable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-40. Summary of Results for Delayed Clearing Fault Analysis

Table O-40 summarizes the results of the fault analysis. For the typical hour, 6 simulations resulted in unstable operation and 10 simulations resulted in unstable operation for the boundary hour.

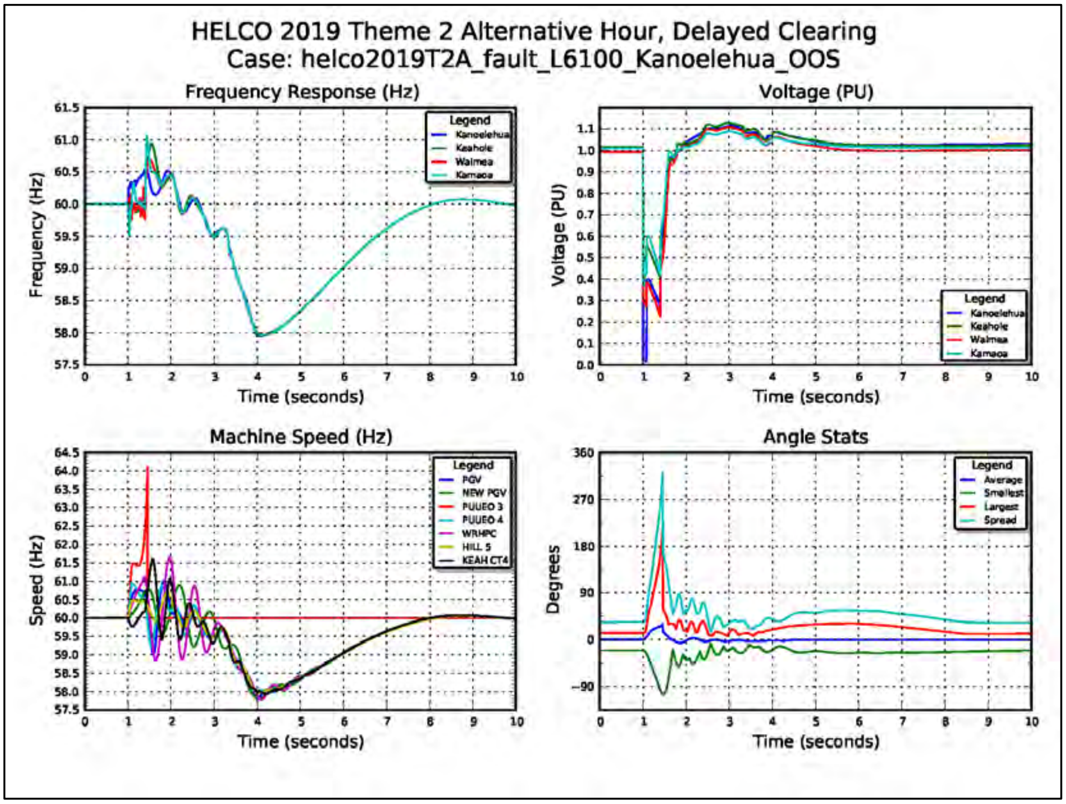


Figure O-112. System Performance for Delayed Clearing Fault

Figure O-112 shows four plots that illustrate system performance for a delayed clearing fault on the L6100 Kanoelehua circuit for the alternative hour. System voltage exceeds 1.1 PU, tripping all 66 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

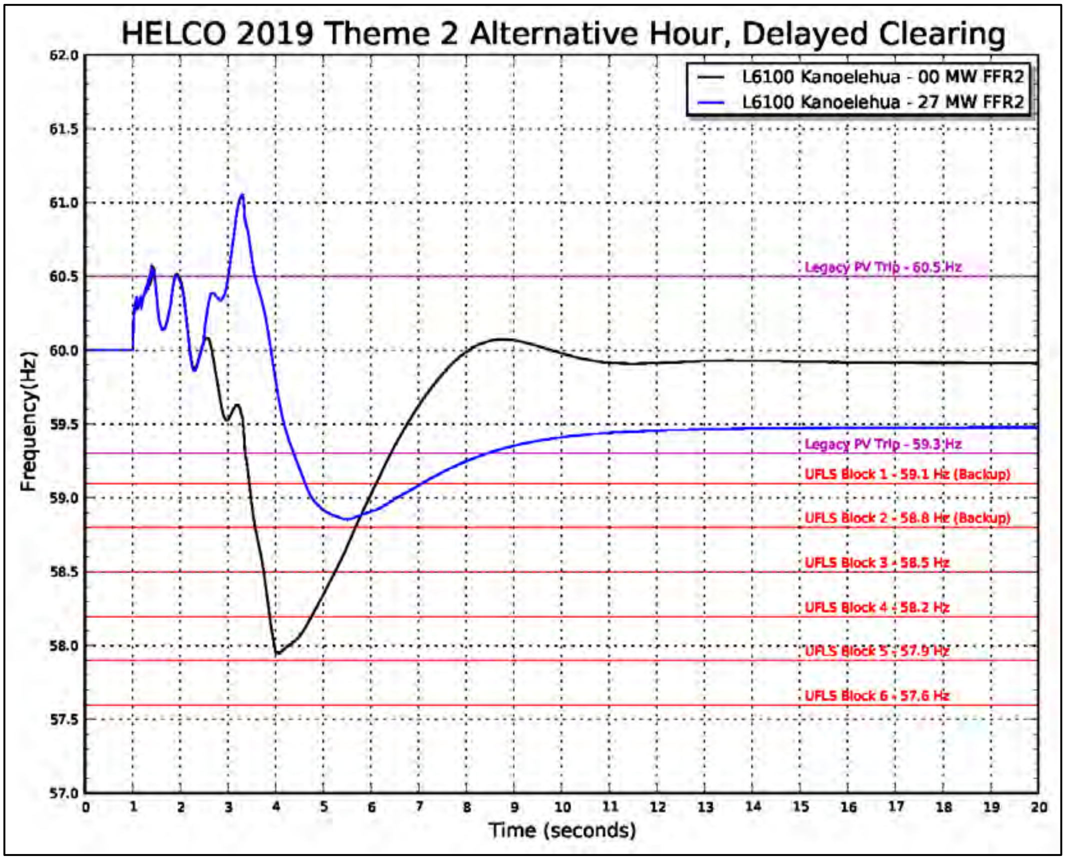


Figure O-113. Frequency Response Profile for FFR2 Alternate Hour

Figure O-113 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 66 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (14.6 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir breaches 58 Hz, requiring 4 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 27 MW. However, this capacity of FFR2 over compensates and initially drives system frequency to 61.1 Hz.

Auto-Schedule control for the BESS is designed to dispatch to full output on a breaker signal from that largest generating unit(s) and is fully deployed in 12-cycles (FFR1) but is not designed to respond to over frequency events. Simulations were performed to determine the capacity of PFR from a BESS with a 3% droop setting. The HELCO generating units are set to 4% droop response.

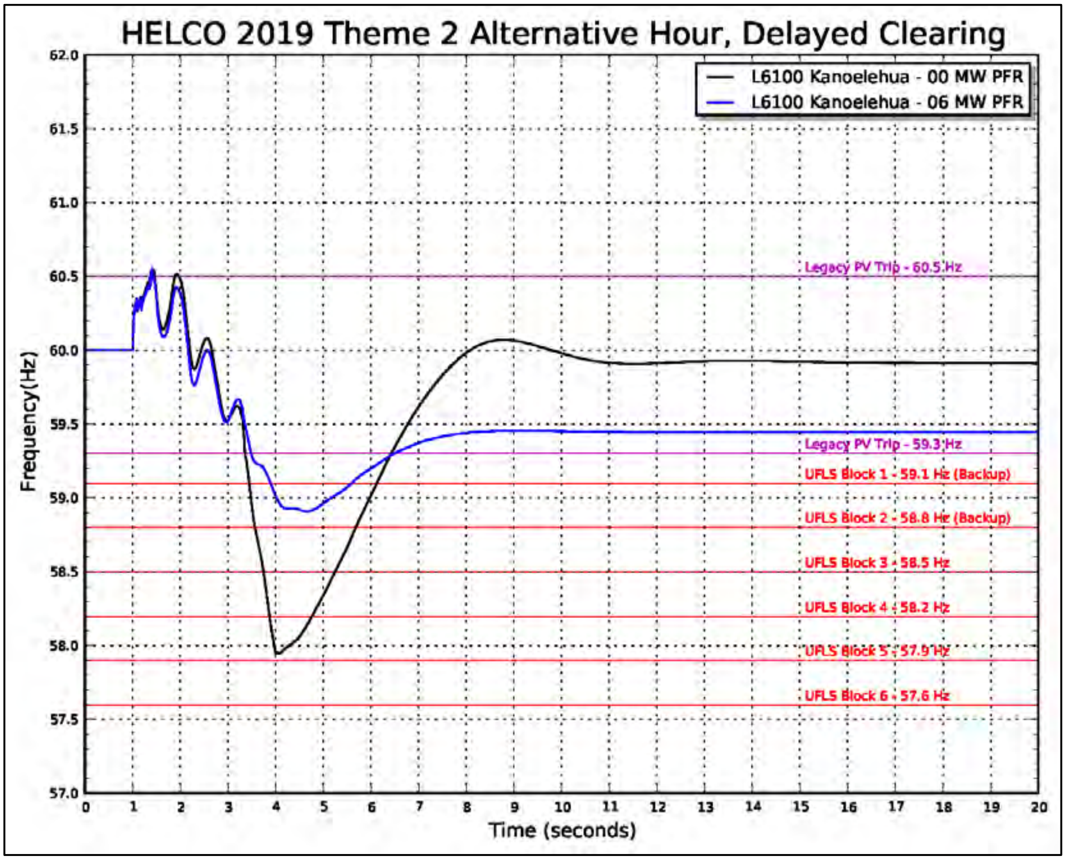


Figure O-114. Frequency Response Profile for PFR Alternate Hour

Figure O-114 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 6 MW. This is in addition to the 14.6 MW of df/dt UFLS from Blocks 1 and 2.

Theme 1 – Aggressive Renewables Plan

Summary

System security analyses were not performed on any resource plan for Theme 1. A high-level fatal flaw assessment was performed on the Theme 1 2045 plans by applying system security requirements for Themes 2 and 3.

Theme 2 – LNG Plan

2023

System security analysis was performed on three hours that were selected from the Theme 2 production cost simulations that represents a typical hour and a boundary condition.

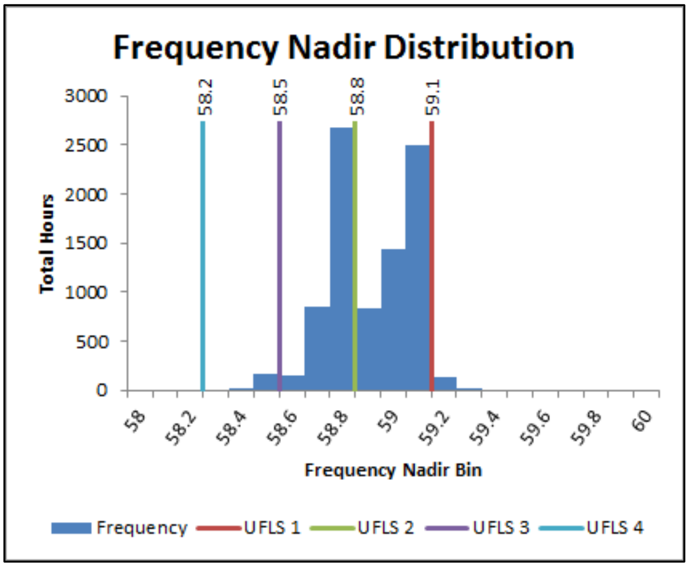


Figure O-115. Frequency Nadir Histogram 2023

Figure O-115 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 2676 hours was 1:00 PM on Friday, January 20. The frequency nadir range for the typical hour is 58.7 - 58.8 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 6 hours was 1:00 PM on Sunday, December 31. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires five blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

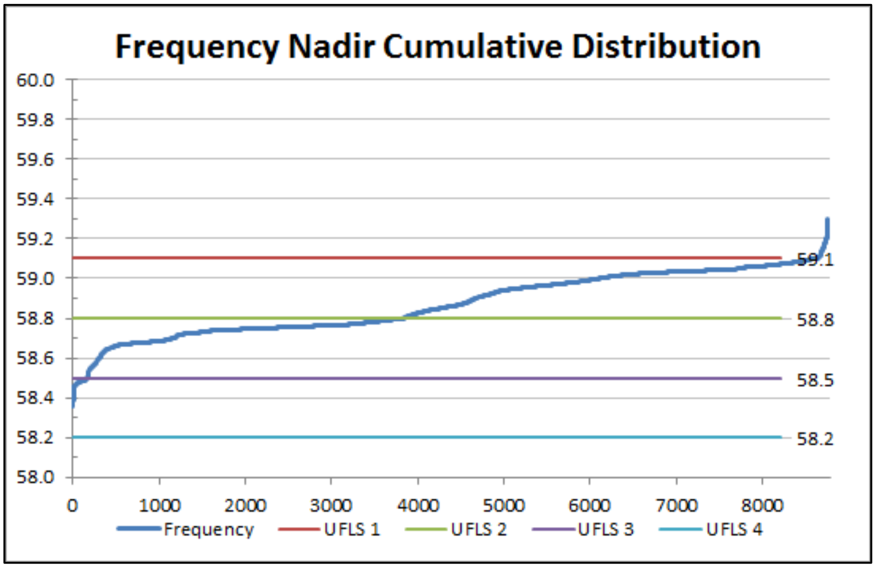


Figure O-116. Frequency Nadir Duration Curve

Figure O-116 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2023 (Typical) Fri 1/20/23 Hour 13			HELCO 2023 (Boundary) Sun 12/31/23 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	33.1	4.9	11.1	33.1	4.9	11.1
Keahole STCC	25.0	7.0			3.13	46.5	146	14.8	10.2	7.8			
Keahole DTCC	54.0	7.0			2.77	71.8	199						
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116	16.6	11.9	7.6			
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70						
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	17.7	2.3	17.7
Geo2	20.0				5.00	40.0	200						
Biomass1	20.0				3.16	28.0	88						
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.5			3.0		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	2.8			2.8		
Apollo	20.5	0.0						6.2			0.0		
HRD	10.5	0.0						0.0			5.3		
Wind1	20.0	0.0											
Wind2	20.0	0.0											
Wind3	20.0	0.0											
Hydro	16.8	0						5			6		
Wind	31.0	0						6			5		
DG-PV	124.7	0						88			88		
Total Kinetic Energy									672			410	
Total Load									184			150	
Total Thermal Generation									84			51	
Total Renewable Generation									100			99	
Total Generation									184			150	
Excess Generation									0			0	
Total Up Regulation									27			7	
Total Down Regulation									46			29	
Legacy DG-PV	59.3Hz Capacity			7.4				59.3Hz Output		5.2	59.3Hz Output		5.2
	60.5Hz Capacity			26.4				60.5Hz Output		18.7	60.5Hz Output		18.7

Table O-41. Unit Commitment and Dispatch Schedule 2023

Table O-41 shows the unit commitment and dispatch for the typical hour (1/20/2023, 1:00 PM), boundary hour (12/31/2023, 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

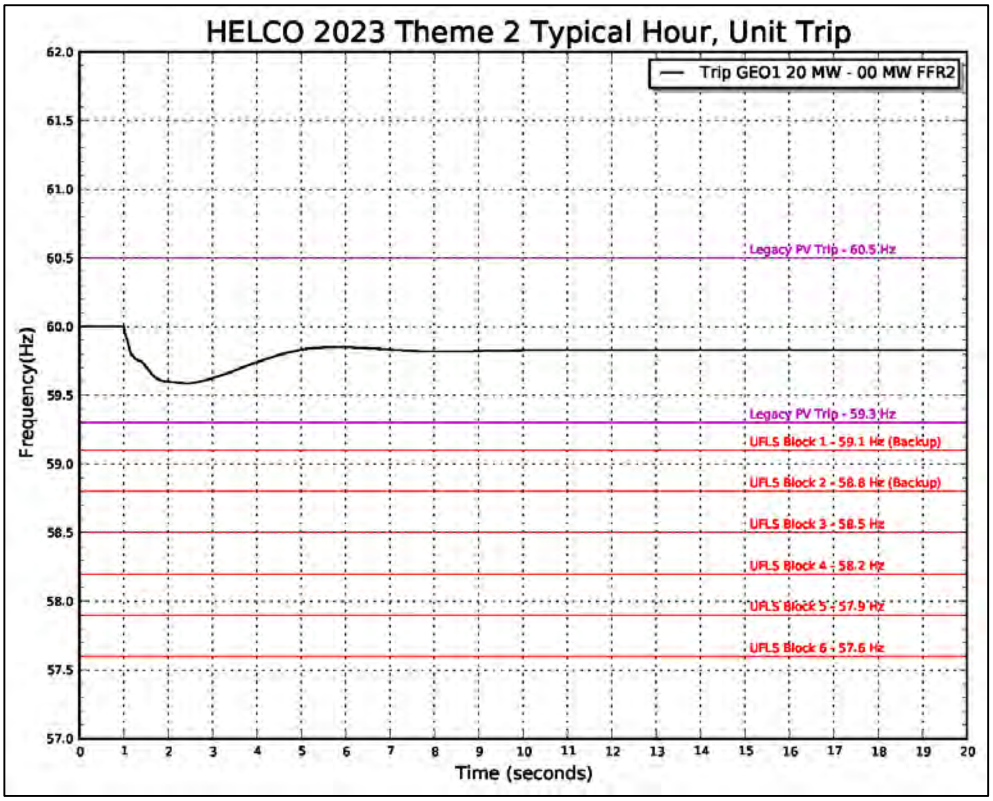


Figure O-117. Frequency Response Profile for FFR2 Typical Hour

Figure O-117 shows the frequency response profile for a geothermal unit trip at 20 MW for a typical hour. System kinetic energy is 672 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5.2 MW. No FFR2 is required because Hawai'i Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 27.6 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

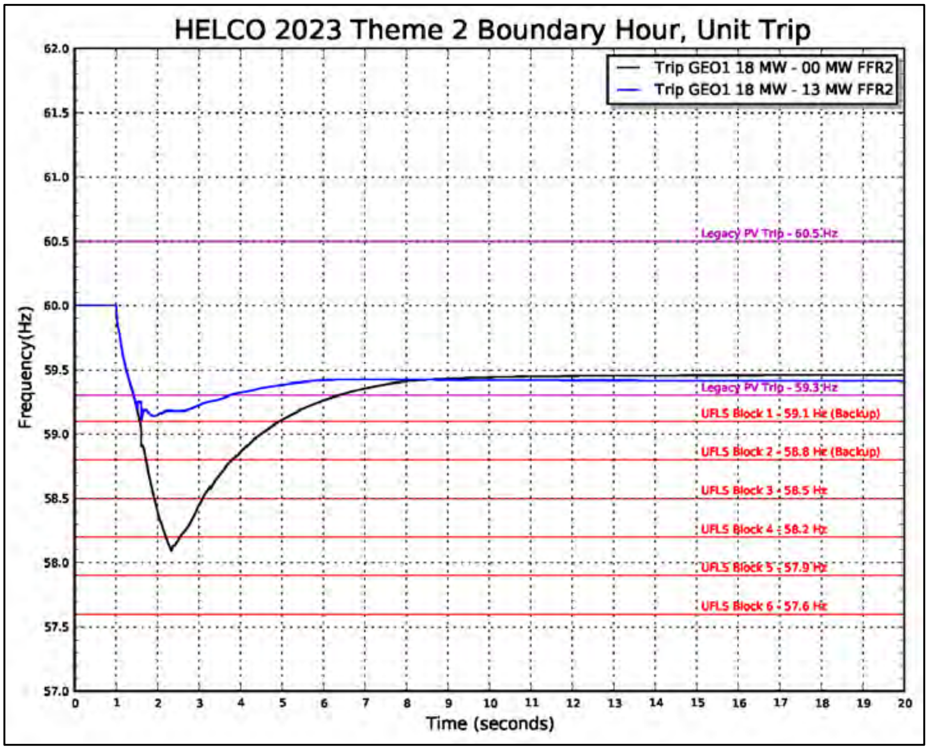


Figure O-118. Frequency Response Profile FFR2 Boundary Hour

Figure O-118 shows the frequency response profile for a geothermal unit trip at 18 MW for a boundary hour. System kinetic energy is 410 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.2 MW. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW. This is in addition to the 22.5 MW of df/dt UFLS from Blocks 1 and 2.

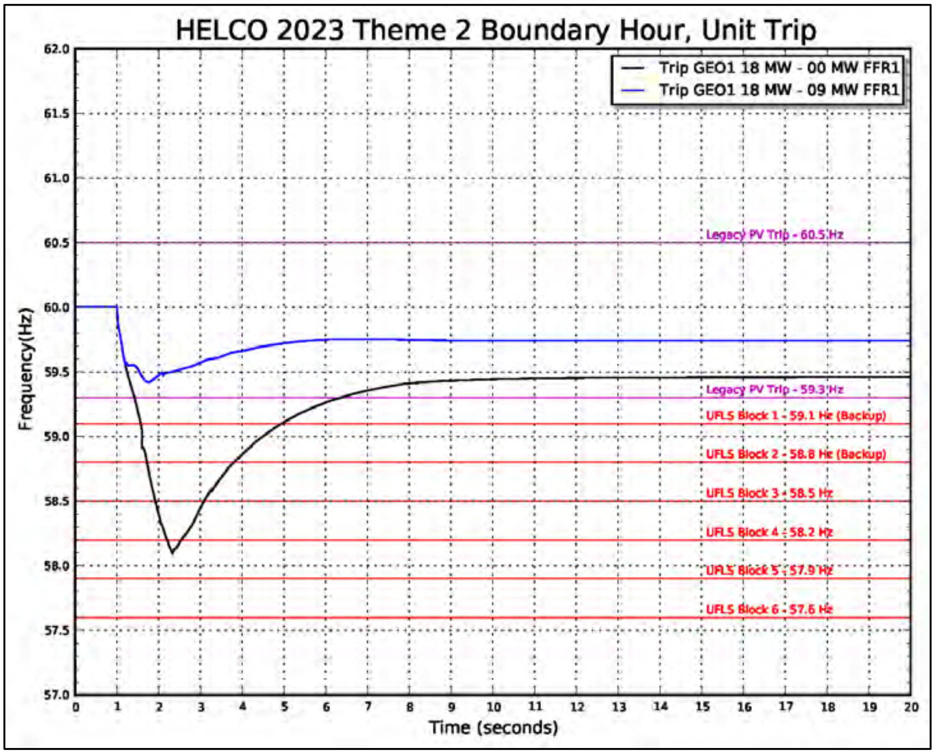


Figure O-119. Frequency Response Profile FFR1 Boundary Hour

Figure O-119 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 22.5 MW of df/dt UFLS from Blocks 1 and 2.

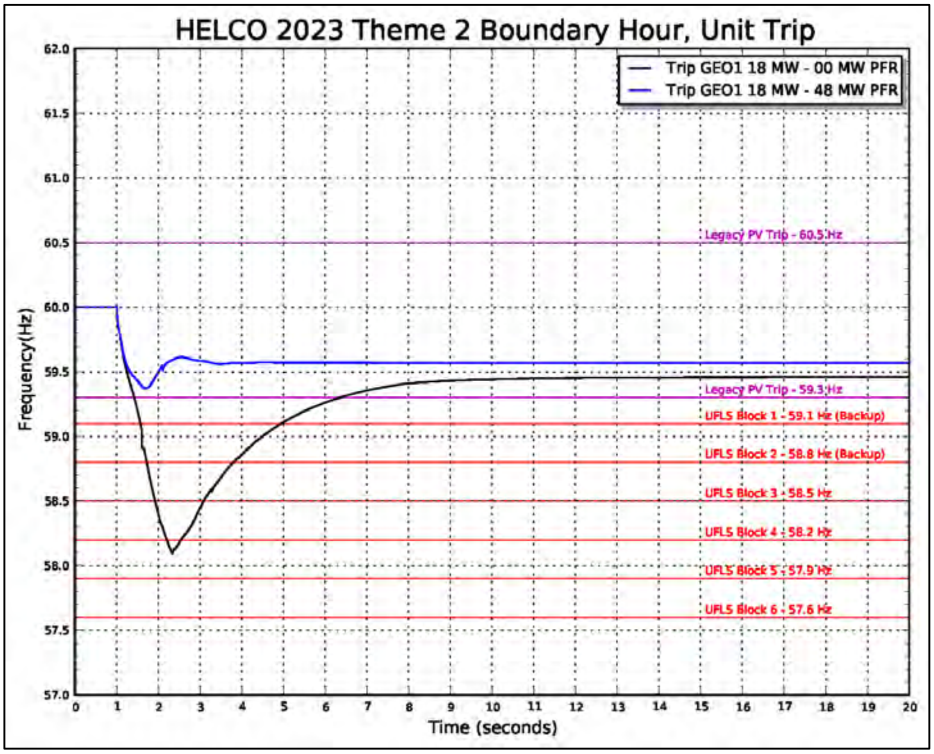


Figure O-120. Frequency Response Profile PFR Boundary Hour

Figure O-120 shows the frequency response profile for the PFR analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 48 MW.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2023 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Unstable
	Kaumana	Unstable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Unstable
	Puna	Stable	Unstable
L6500	Kaumana	Stable	Unstable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Unstable
	Wailuku	Stable	Unstable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Unstable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Unstable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Stable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Unstable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Stable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Unstable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Unstable
L8800	Haina	Stable	Unstable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Stable	Unstable
	Wailuku	Stable	Unstable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-42. Summary of Results Delayed Clearing Fault Analysis

Table O-42 summarizes the results of the fault analysis. For the typical hour, 2 simulations resulted in unstable operation and 18 simulations resulted in unstable operation for the boundary hour.

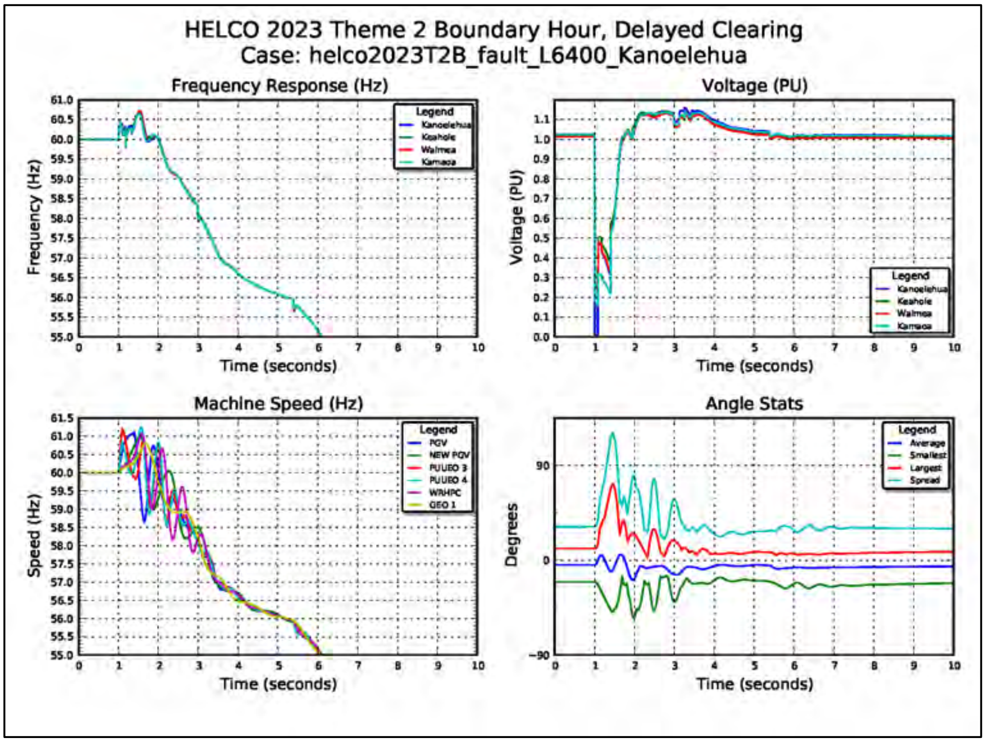


Figure O-121. System Performance for Delayed Clearing Fault

Figure O-121 shows four plots that illustrate system performance for a delayed clearing fault on the L6400 Kanoelehua circuit for the boundary hour. System voltage exceeds 1.1 PU, tripping all units on the system including 88 MW of DG-PV on over voltage. The system will not survive an extended over voltage event. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

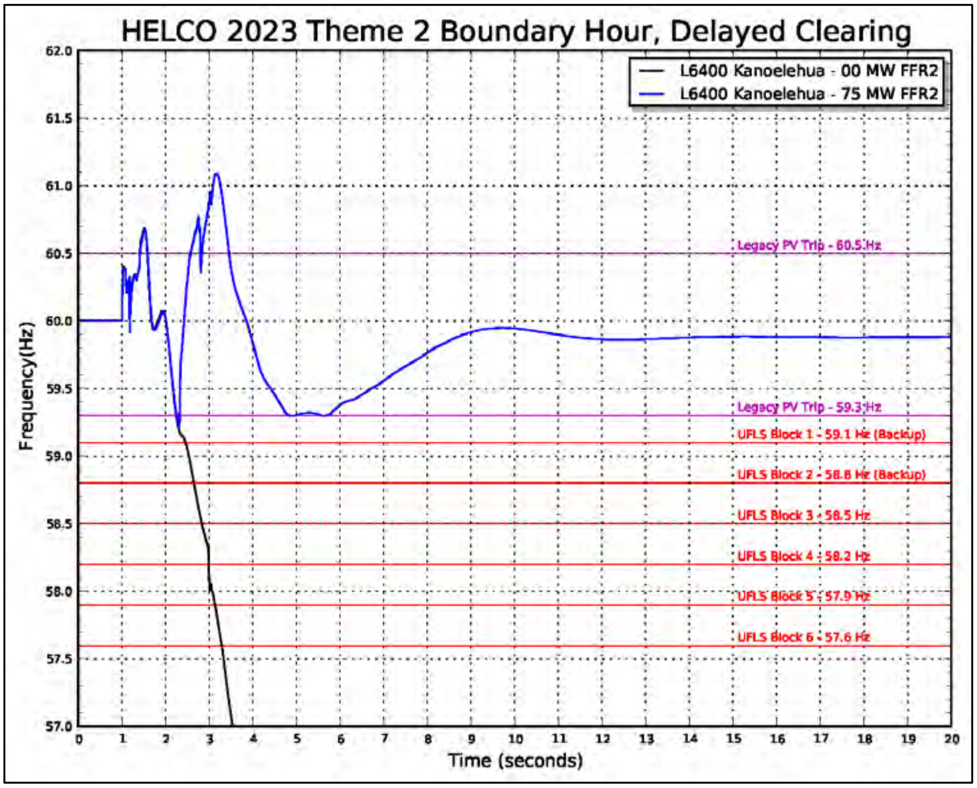


Figure O-122. Frequency Response Profile for FFR2 Boundary Hour

Figure O-122 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. All generating resources disconnect from the system on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (22.5 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay below 57 Hz despite 5 blocks of UFLS. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 75 MW. However, this capacity of FFR2 over compensates and initially drives system frequency to 61.1 Hz.

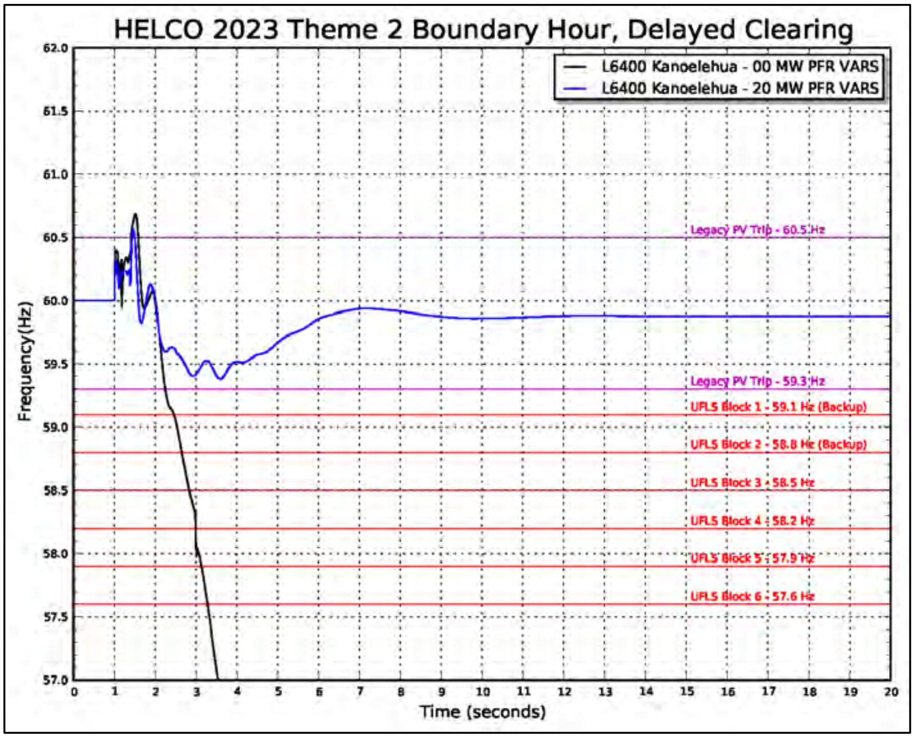


Figure O-123. Frequency Response Profile for PFR Boundary Hour

Figure O-123 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 20 MW. This is in addition to the 22.5 MW of df/dt UFLS from Blocks 1 and 2.

2045

System security analysis was performed on three hours that were selected from the Theme 2 production cost simulations that represents a typical hour and a boundary condition.

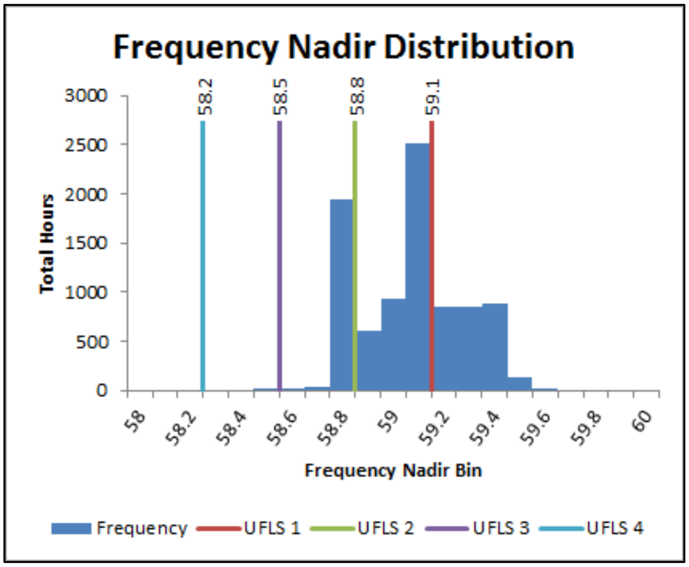


Figure O-124. Frequency Nadir Histogram 2045

Figure O-124 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1947 hours was 3:00 PM on Sunday, April 9. The frequency nadir range for the typical hour is 58.7 - 58.8 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 6 hours was 1:00 PM on Friday, February 10. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires 3 blocks of UFLS to stabilize system frequency.

The alternate hour was selected from the boundary hours to maximize DG-PV for the purpose of analyzing loss of generation contingency caused by delay cleared faults.

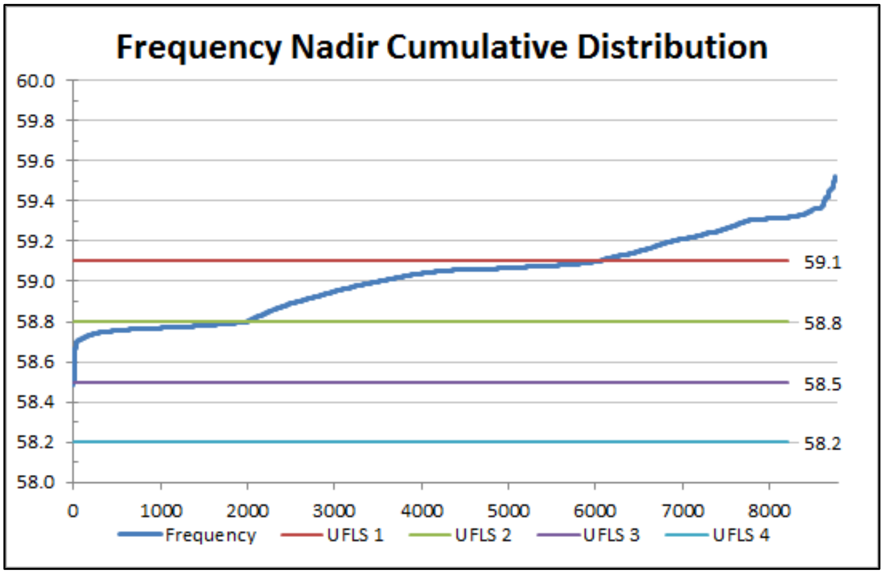


Figure O-125. Frequency Nadir Duration Curve 2045

Figure O-125 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2045 (Typical) Sun 4/9/45 Hour 15			HELCO 2045 (Boundary) Fri 2/10/45 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	33.7	4.3	11.7			
Keahole STCC	25.0	7.0			3.13	46.5	146						
Keahole DTCC	54.0	7.0			2.77	71.8	199						
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116				26.4	2.1	17.4
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70						
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	20.0	0.0	20.0
Geo2	20.0				5.00	40.0	200	19.6	0.4	19.6	20.0	0.0	20.0
Biomass1	20.0				3.16	28.0	88	12.3	7.7	12.3	18.0	2.0	18.0
HELCO Hydro	4.7	0.0			1.07	5.6	6	4.1			1.9		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	0.8			0.0		
Apollo	20.5	0.0						0.0			7.5		
HRD	10.5	0.0						3.6			1.3		
Wind1	20.0	0.0						0.0			4.0		
Wind2	20.0	0.0						0.0			4.0		
Wind3	20.0	0.0											
Hydro	16.8	0						5			2		
Wind	31.0	0						4			17		
DG-PV	158	0						70			83		
Total Kinetic Energy									699			640	
Total Load									165			186	
Total Thermal Generation									86			84	
Total Renewable Generation									79			102	
Total Generation									165			186	
Excess Generation									0			0	
Total Up Regulation									12			4	
Total Down Regulation									64			75	
Legacy DG-PV	59.3Hz Capacity			0.0				59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-43. Unit Commitment and Dispatch Schedule 2045

Table O-43 shows the unit commitment and dispatch for the typical hour (4/9/2045, 3:00 PM), boundary hour (2/10/2045, 1:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

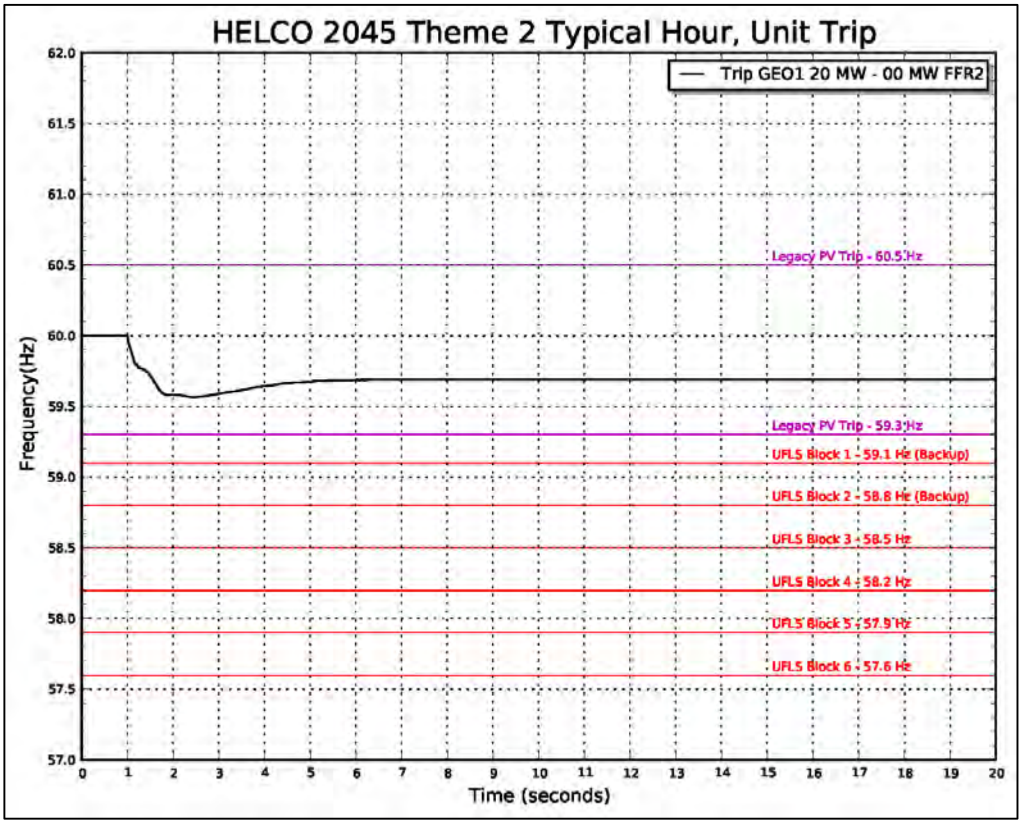


Figure O-126. Frequency Response Profile FFR2 Typical Hour

Figure O-126 shows the frequency response profile for a geothermal unit trip at 20 MW for a typical hour. System kinetic energy is 699 MW-sec. No FFR2 is required because Hawai'i Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 24.8 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

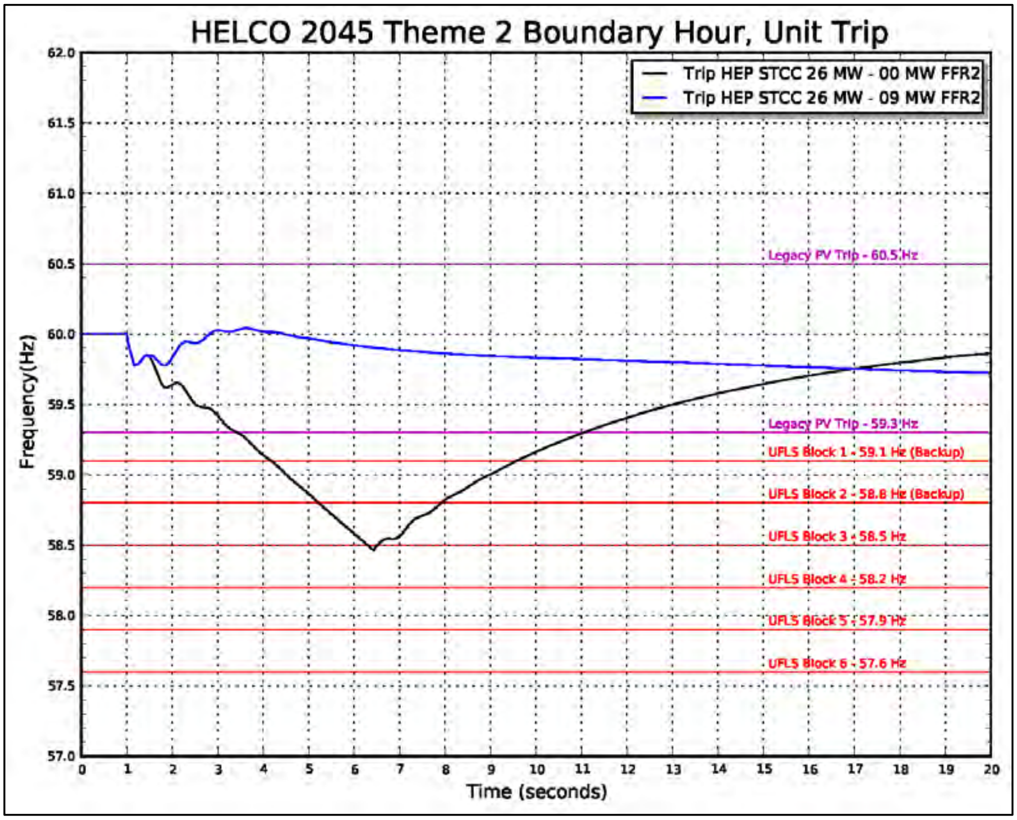


Figure O-127. Frequency Response Profile FFR2 Boundary Hour

Figure O-127 shows the frequency response profile for a HEP STCC unit trip at 26 MW for a boundary hour. System kinetic energy is 640 MW-sec. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 27.9 MW of df/dt UFLS from Blocks 1 and 2.

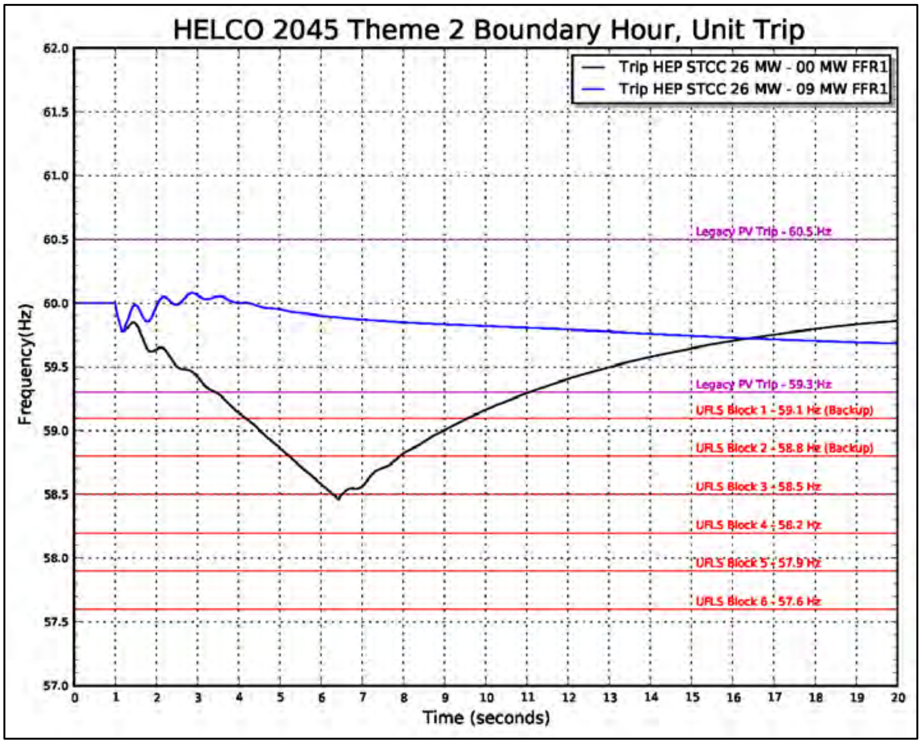


Figure O-128. Frequency Response Profile FFR1 Boundary Hour

Figure O-128 shows the frequency response profile for the FFR1 analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 27.9 MW of df/dt UFLS from Blocks 1 and 2.

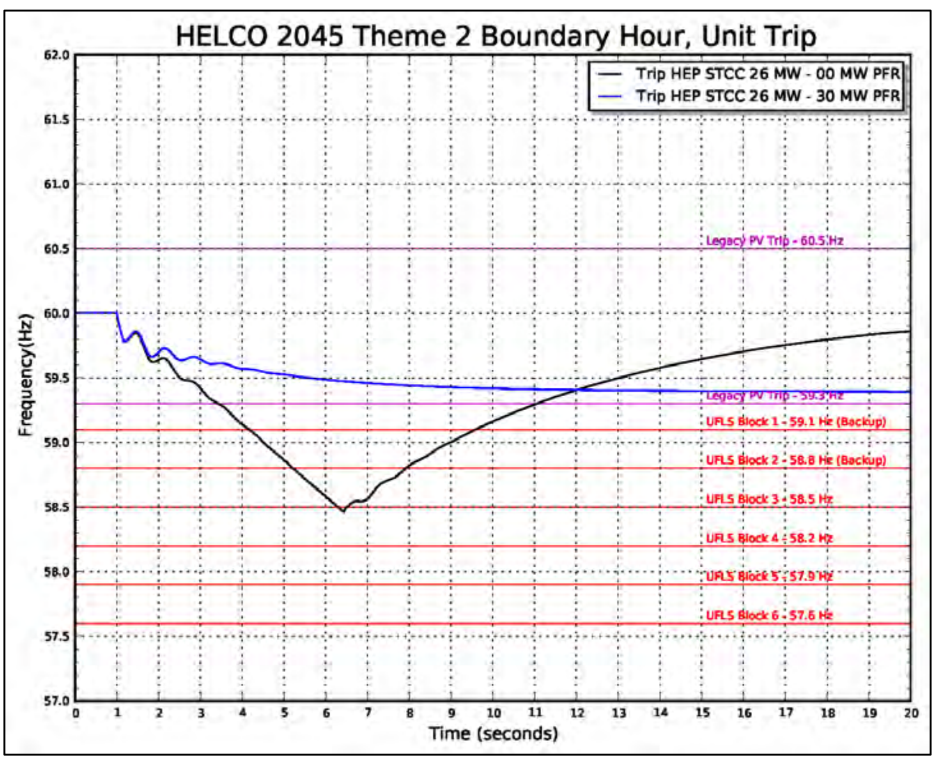


Figure O-129. Frequency Response Profile PFR Boundary Hour

Figure O-129 shows the frequency response profile for the PFR analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 30 MW. This is in addition to the 27.9 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2045 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Unstable	Stable
	Kaumana	Unstable	Stable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Unstable	Stable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Unstable	Stable
	Wailuku	Unstable	Stable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Stable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Unstable	Stable
	Puueo	Unstable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Unstable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Unstable	Stable
	Wailuku	Unstable	Stable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-44. Summary of Results Delayed Clearing Fault Analysis

Table O-44 summarizes the results of the fault analysis. For the typical hour, 11 simulations resulted in unstable operation and 2 simulations resulted in unstable operation for the boundary hour.

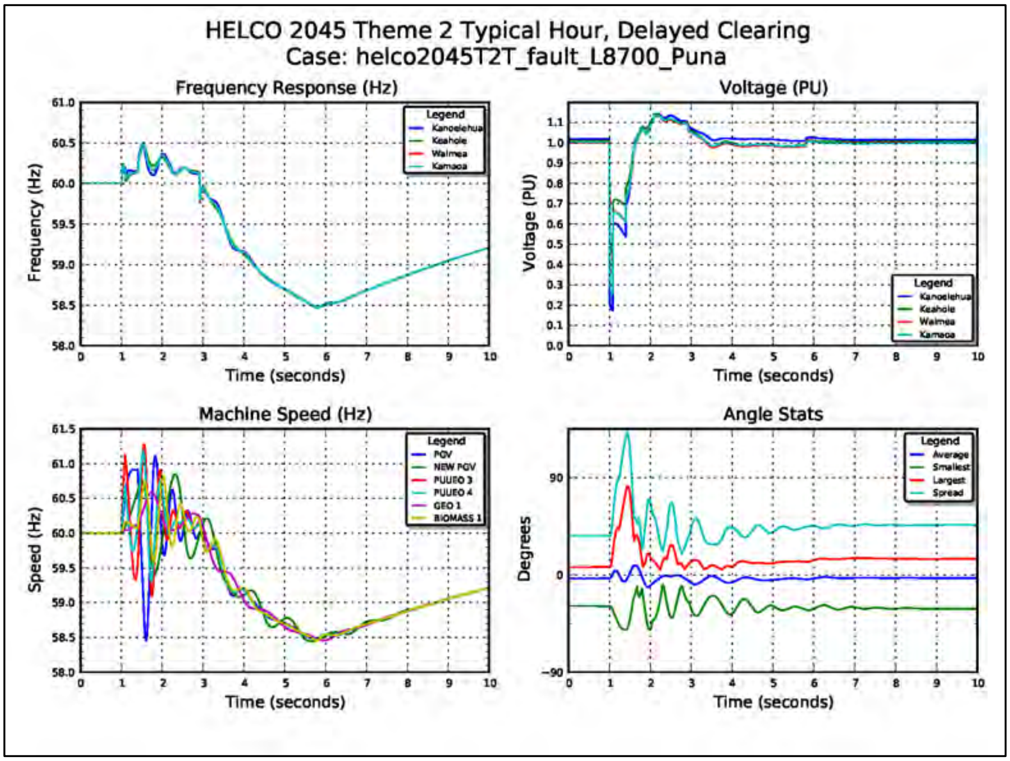


Figure O-130. System Performance to Delayed Clearing Fault

Figure O-130 shows four plots that illustrate system performance for a delayed clearing fault on the L8700 Puna circuit for a typical hour. System voltage exceeds 1.1 PU, tripping all 70 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

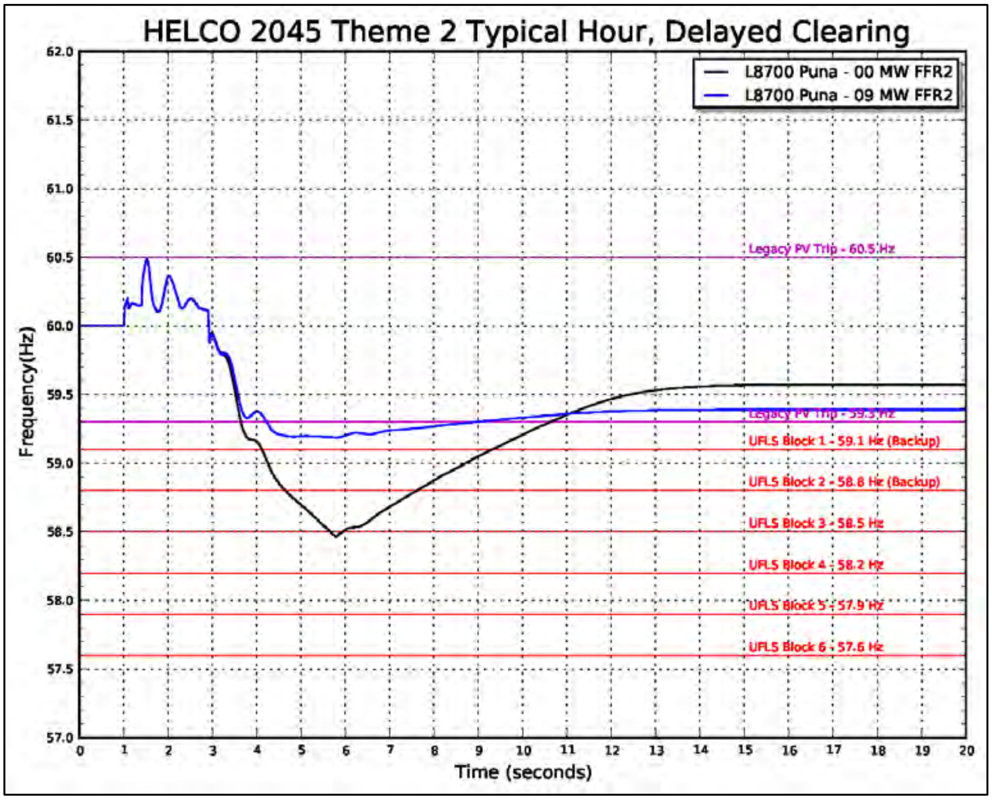


Figure O-131. Frequency Response Profile for FFR2 Typical Hour

Figure O-131 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 70 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (24.8 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir hits 58.5 Hz, requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9 MW. This is in addition to the 24.8 MW of df/dt UFLS from Blocks 1 and 2.

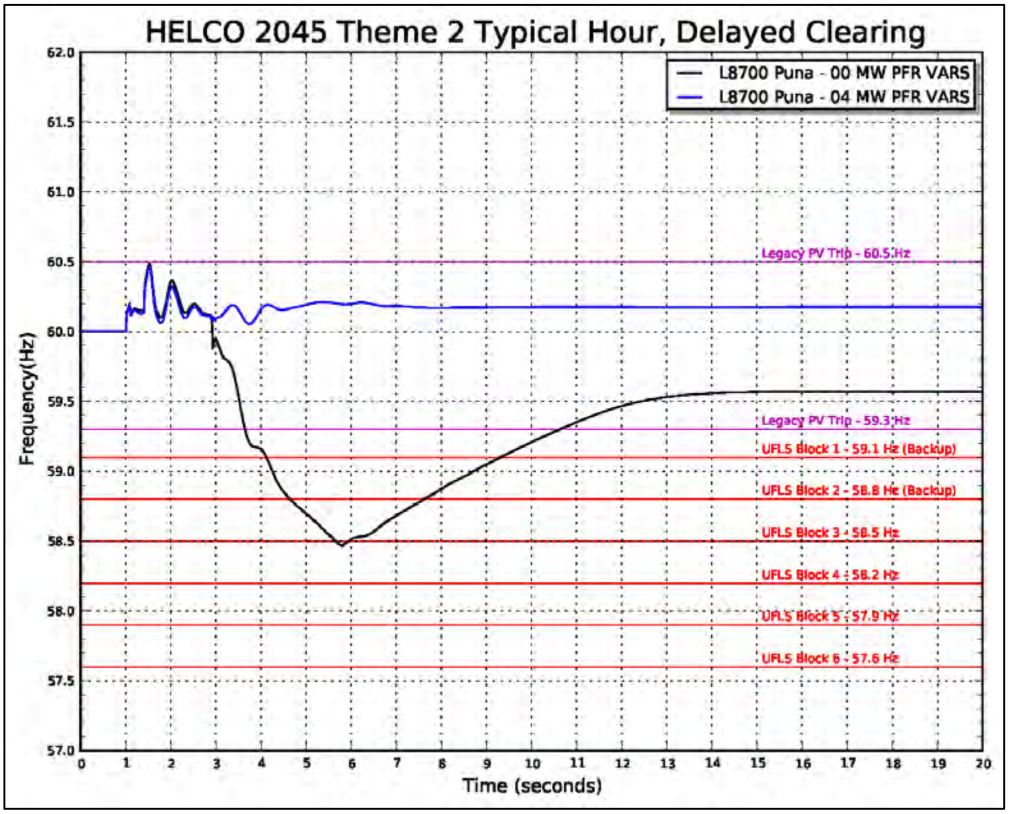


Figure O-132. Frequency Response Profile for PFR Typical Hour

Figure O-132 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 4 MW. This is in addition to the 24.8 MW of df/dt UFLS from Blocks 1 and 2.

Theme 3 – No LNG Plan

2023

System security analysis was performed on three hours that were selected from the Theme 3 production cost simulations that represents a typical hour and a boundary condition. The boundary hour has 82 MW of DG-PV so selection of an alternate hour was not required.

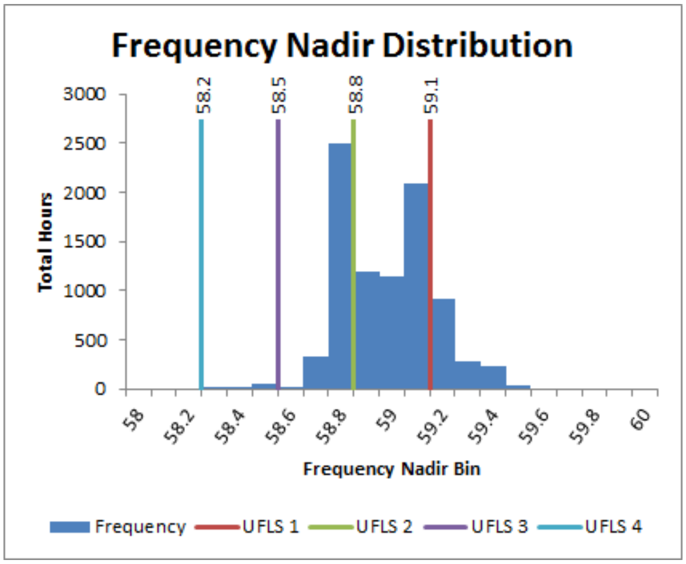


Figure O-133. Frequency Nadir Histogram 2023

Figure O-133 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 2493 hours was 9:00 AM on Thursday, October 26. The frequency nadir range for the typical hour is 58.7 - 58.8 Hz that requires 2 blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 1 hour was 10:00 AM on Monday, December 11. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires five blocks of UFLS to stabilize system frequency.

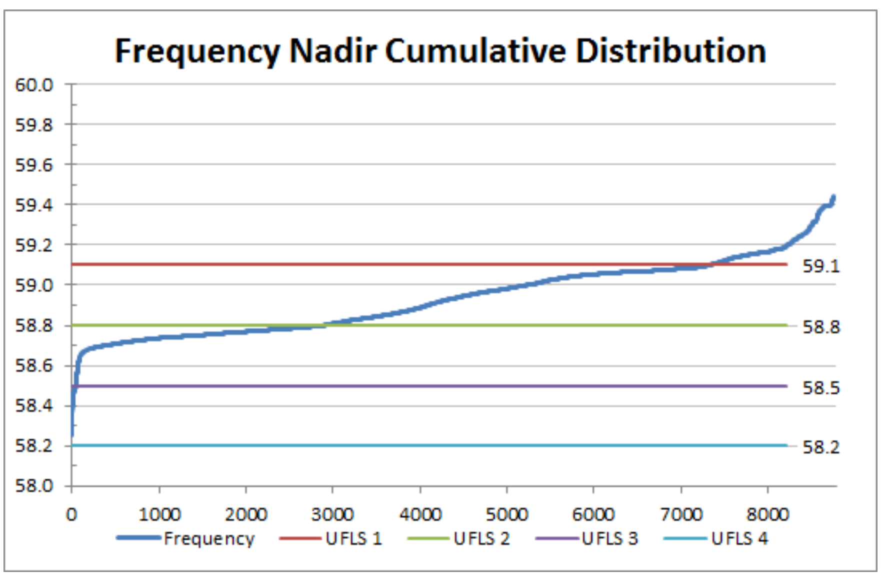


Figure O-134. Frequency Nadir Cumulative Distribution

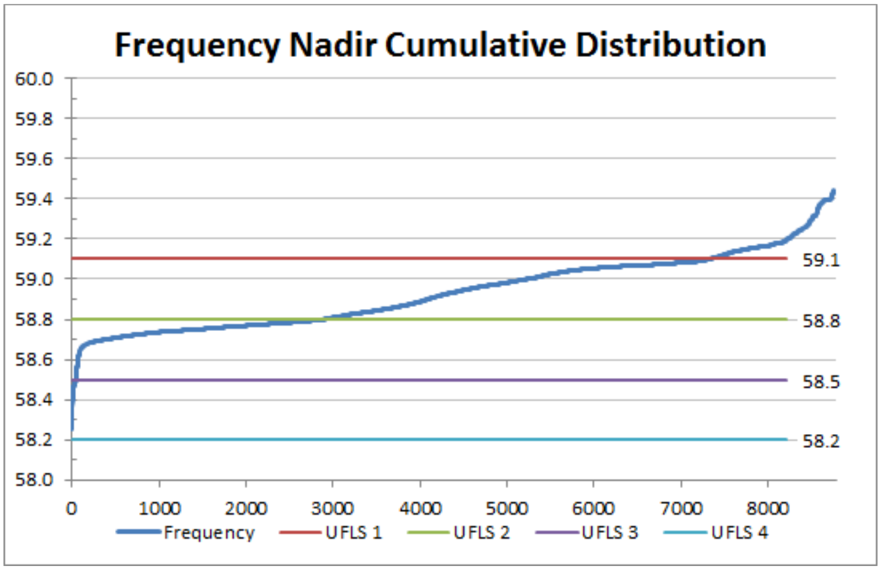


Figure O-135. Frequency Nadir Duration Curve 2023

Figure O-135 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2023 (Typical) Thu 10/26/23 Hour 9			HELCO 2023 (Boundary) Mon 12/11/23 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	36.4	1.6	14.4	36.4	1.6	14.4
Keahole STCC	25.0	7.0			3.13	46.5	146				21.9	3.1	14.9
Keahole DTCC	54.0	7.0			2.77	71.8	199	25.3	28.7	18.3			
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116						
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70	11.0	9.5	3.0			
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	20.0	0.0	20.0
Geo2	20.0				5.00	40.0	200						
Biomass1	20.0				3.16	28.0	88						
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.1			3.0		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	0.0			0.0		
Apollo	20.5	0.0						15.6			7.1		
HRD	10.5	0.0						4.5			0.0		
Hydro	16.8	0						13%	2		18%	3	
Wind	31.0	0						65%	20		23%	7	
DG-PV	150.4	0						31%	47		55%	82	
Total Kinetic Energy									679			556	
Total Load									162			171	
Total Thermal Generation									93			78	
Total Renewable Generation									70			92	
Total Generation									162			171	
Excess Generation									0			0	
Total Up Regulation									40			5	
Total Down Regulation									56			49	
Legacy DG-PV	59.3Hz Capacity			7.4				59.3Hz Output		2.3	59.3Hz Output		4.0
	60.5Hz Capacity			26.4				60.5Hz Output		8.3	60.5Hz Output		14.4

Table O-45. Unit Commitment and Dispatch Schedule 2023

Table O-45 shows the unit commitment and dispatch for the typical hour (10/26/2023, 9:00 AM), boundary hour (12/11/2023, 10:00 AM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

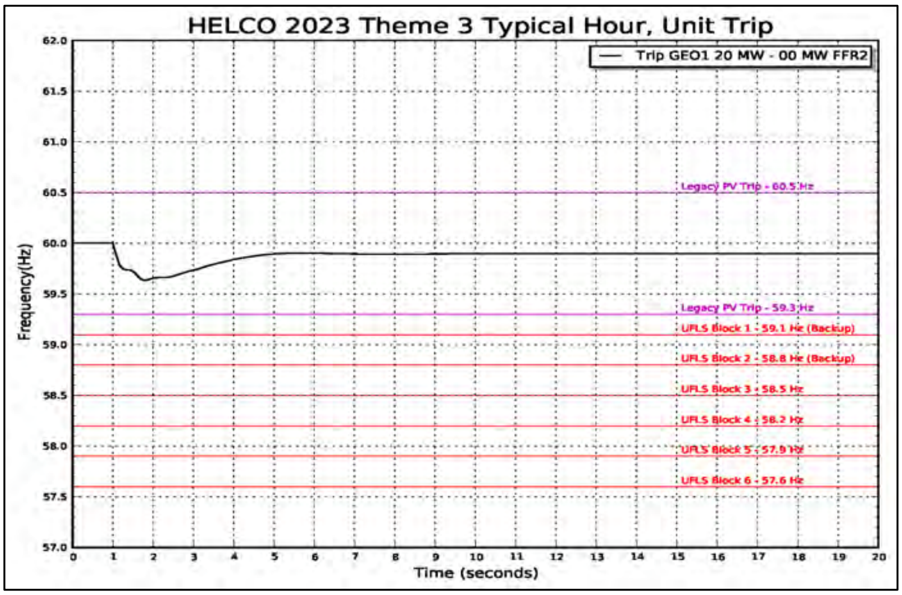


Figure O-136. Frequency Response Profile for FFR2 Typical Hour

Figure O-136 shows the frequency response profile for a geothermal unit trip at 20 MW for a typical hour. System kinetic energy is 679 MW-sec and the capacity of legacy PV that will disconnect from the system is 2.3 MW. No FFR2 is required because Hawai'i Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was shed was 24.3 MW that is basically FFR at the distribution circuit level as opposed to behind the meter.

The effectiveness of df/dt is evident in the frequency response profile. The initial RoCoF is immediately reduced when UFLS Blocks 1 and 2 are shed. This avoids tripping legacy PV.

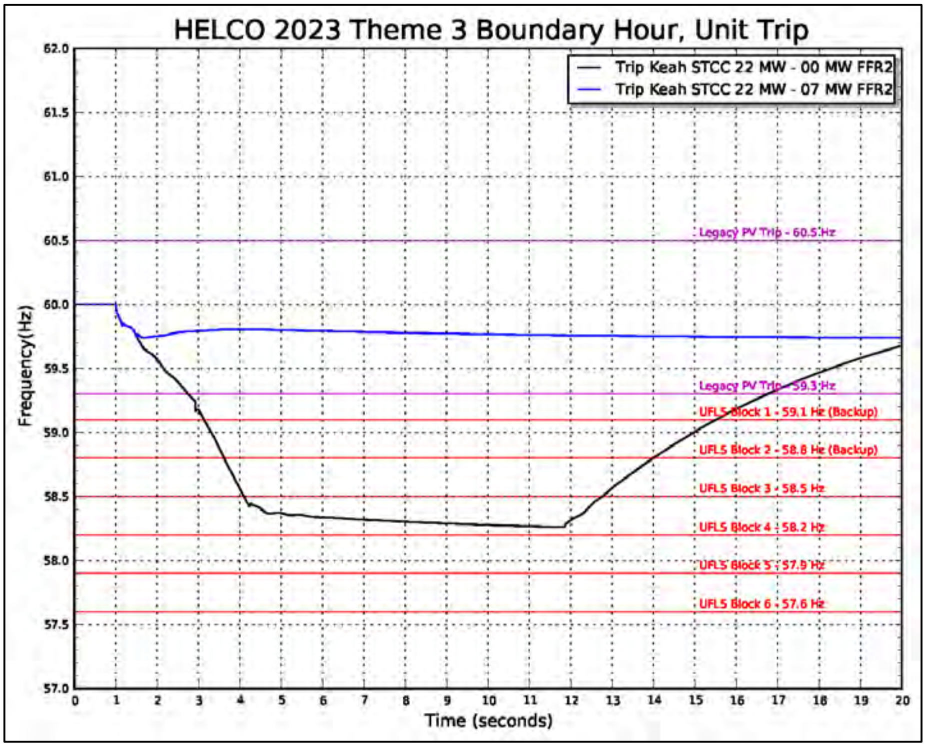


Figure O-137. Frequency Response Profile for FFR2 Boundary Hour

Figure O-137 shows the frequency response profile for a Keahole STCC trip at 22 MW for a boundary hour. System kinetic energy is 556 MW-sec and the capacity of legacy PV that will disconnect from the system is 4 MW. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 7 MW. This is in addition to the 25.7 MW of df/dt UFLS from Blocks 1 and 2.

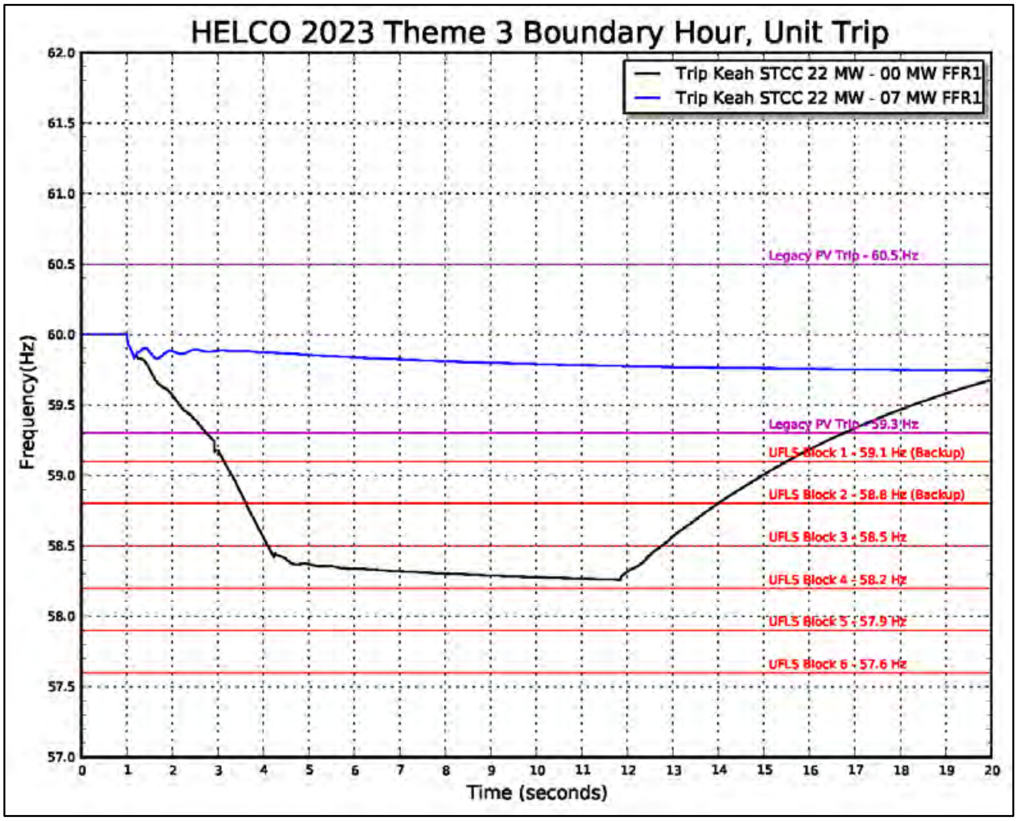


Figure O-138. Frequency Response Profile for FFR1 Boundary Hour

Figure O-138 shows the frequency response profile for the FFR1 analysis for the boundary hour. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW. This is in addition to the 25.7 MW of df/dt UFLS from Blocks 1 and 2.

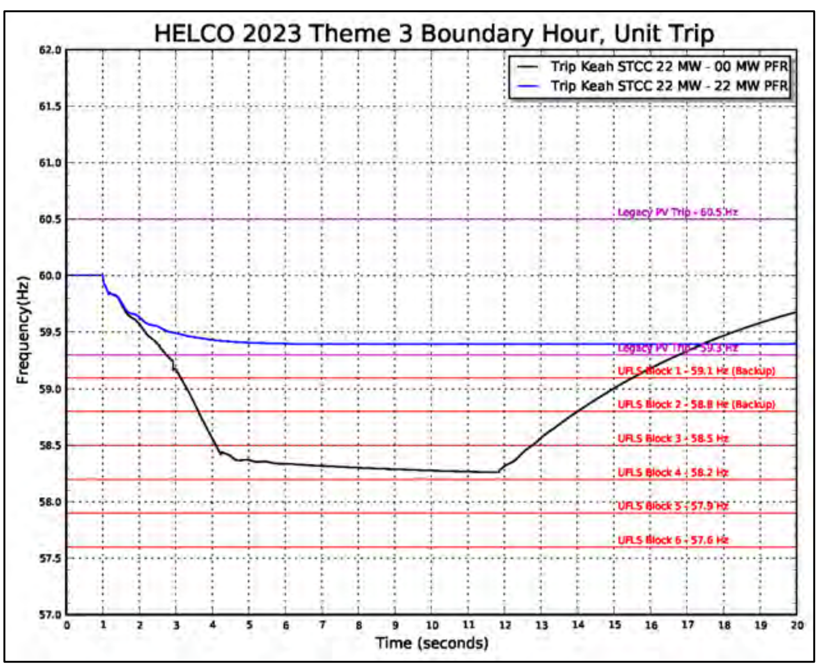


Figure O-139. Frequency Response Profile for PFR Boundary Hour

Figure O-139. shows the frequency response profile for the PFR analysis for the boundary hour. The capacity of PFR required to bring the system into compliance with TPL-001 is 22 MW. This is in addition to the 25.7 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2023 69kV Fault Delayed Clearing Analysis			
Line No Outage	3-phase Fault Near	Typical Hour Condition	Boundary Hour Condition
L6100	Kanoelehua	Stable	Unstable
	Kaumana	Stable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Stable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Stable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Unstable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Stable	Stable
	Wailuku	Unstable	Unstable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-46. Summary of Results Delayed Clearing Fault Analysis

Table O-46 summarizes the results of the fault analysis. For the typical hour, 3 simulations resulted in unstable operation and 8 simulations resulted in unstable operation for the boundary hour.

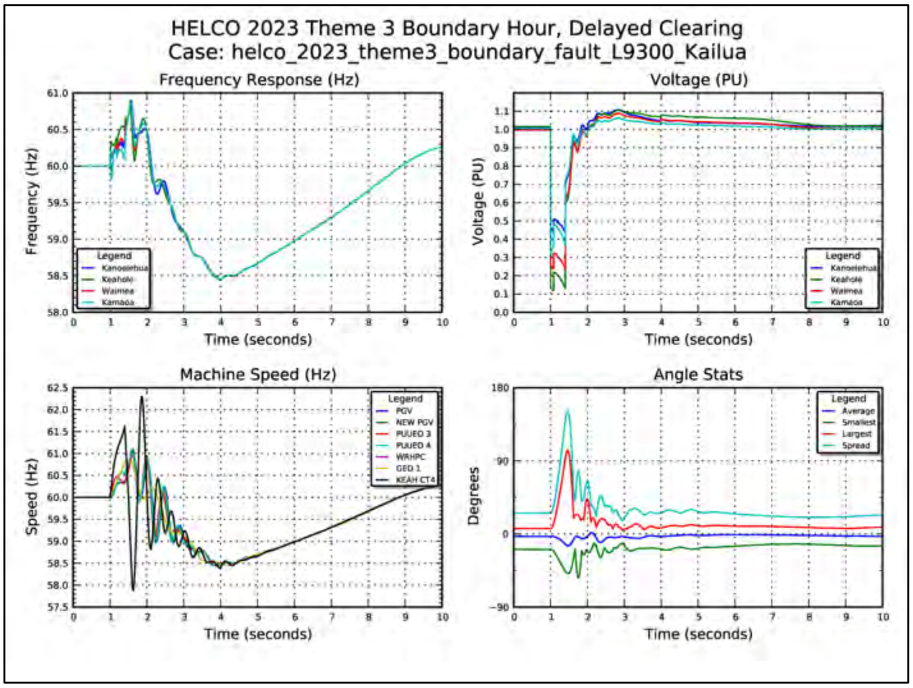


Figure O-140. System Performance to Delayed Clearing Fault

Figure O-140 shows four plots that illustrate system performance for a delayed clearing fault on the L9300 Kailua circuit for the boundary hour. System voltage exceeds 1.1 PU, tripping all 82 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

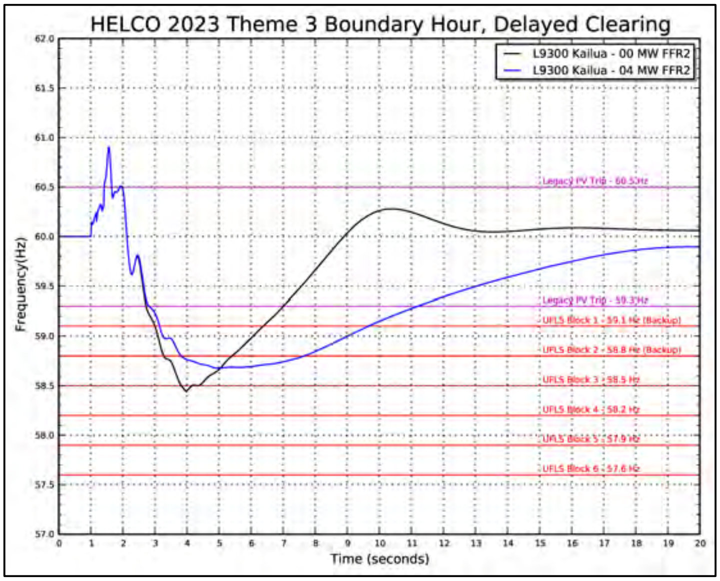


Figure O-141. Frequency Response Profile FFR2 Boundary Hour

Figure O-141 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 82 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (25.7 MW), causing a momentary stabilization of system frequency (black plot). Frequency continues to decay until the nadir hits 58.5 Hz, requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 4 MW.

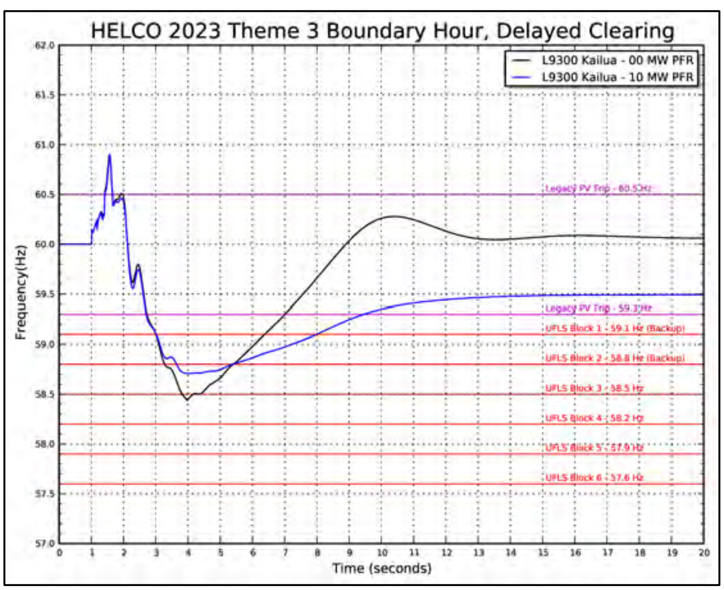


Figure O-142. Frequency Response Profile PFR Boundary Hour

Figure O-142 shows the frequency response profile for the PFR analysis provided by a BESS. The capacity of PFR at 3% droop response required to bring the system into compliance with TPL-001 is 10 MW. This is in addition to the 25.7 MW df/dt UFLS from Blocks 1 and 2.

2045

System security analysis was performed for two hours that represents a typical hour and a boundary condition.

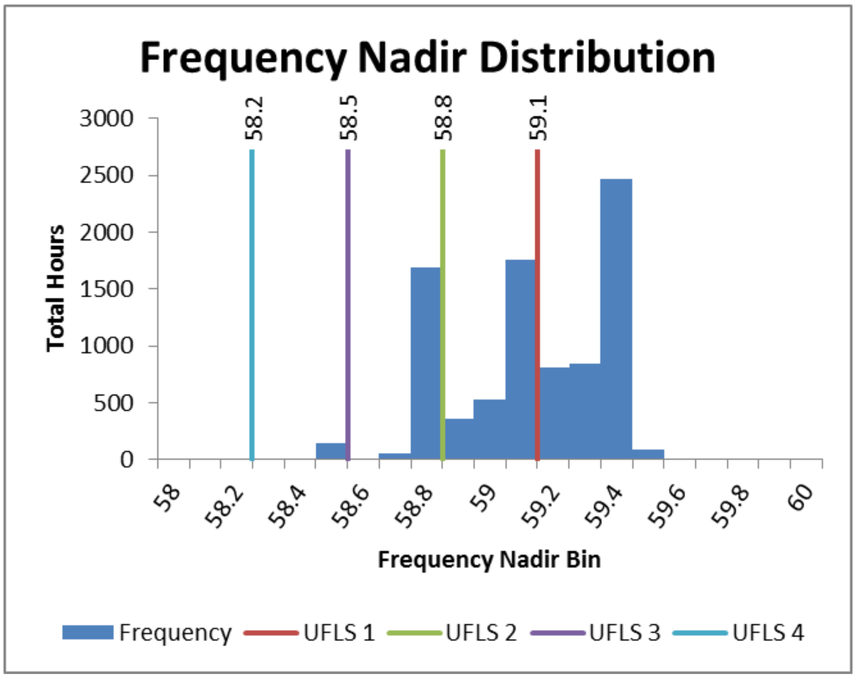


Figure O-143. Frequency Nadir Histogram 2045

Figure O-143 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour selected from the maximum distribution of 1690 hours was 9:00 AM on Wednesday, January 18. The frequency nadir range for the typical hour is 58.7 – 58.8 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 148 hours was 5:00 PM on Sunday, December 24. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

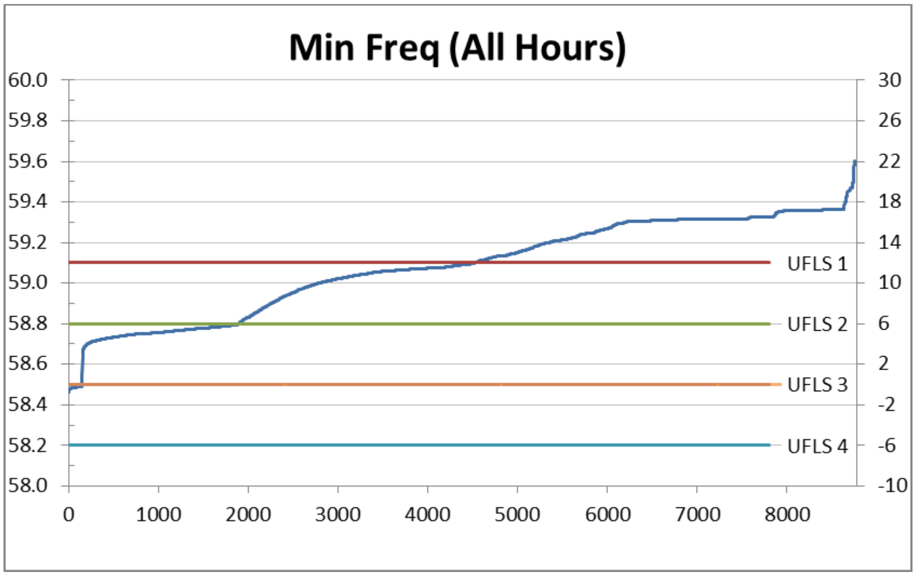


Figure O-144. Frequency Nadir Duration Curve 2045

Figure O-144 shows the frequency nadir duration curve for the entire year.

Unit Commitment Order	Unit Ratings							HELCO 2045 (Typical) Wed 1/18/45 Hour 9			HELCO 2045 (Boundary) Sun 12/24/45 Hour 17		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0			2.94	59.4	174	30.7	7.3	8.7	36.9	1.1	14.9
Keahole STCC	25.0	7.0			3.13	46.5	146						
Keahole DTCC	54.0	7.0			2.77	71.8	199						
Keahole CT4	20.0	7.0			2.10	25.2	53						
Keahole CT5	20.0	7.0			2.10	25.2	53						
HEP STCC	28.5	9.0			1.96	58.9	116						
HEP DTCC	60.0	18.5			1.78	94.4	168						
Hill 5	13.5	5.0			2.20	15.6	34						
Hill 6	20.5	8.0			2.53	27.5	70						
Keah CT2	13.8	5.0			4.44	22.2	99						
Puna CT3	20.0	7.0			4.96	29.6	147						
Geo1	20.0				5.00	40.0	200	20.0	0.0	20.0	19.8	0.2	19.8
Geo2	20.0				5.00	40.0	200	20.0	0.0	20.0	19.3	0.7	19.3
Biomass1	20.0				3.16	28.0	88	12.1	7.9	12.1			
HELCO Hydro	4.7	0.0			1.07	5.6	6	2.5			3.0		
Wailuku Hydro	12.1	0.0			2.42	12.2	30	4.0			0.8		
Apollo	20.5	0.0						0.0			12.7		
HRD	10.5	0.0						0.0			0.7		
Hydro	16.8	0						6			4		
Wind	31.0	0						0			13		
DG-PV	435	0						109			87		
Total Kinetic Energy									699			610	
Total Load									198			181	
Total Thermal Generation									83			76	
Total Renewable Generation									116			105	
Total Generation									198			181	
Excess Generation									0			0	
Total Up Regulation									15			2	
Total Down Regulation									61			54	
Legacy DG-PV	59.3Hz Capacity			0.0				59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			0.0				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-47. Unit Commitment and Dispatch Schedule 2045

Table O-47 shows the unit commitment and dispatch schedules for the typical hour (1/18/45 at 9:00 AM) and boundary hour (12/24/45 at 5:00 PM).

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to bring the system into compliance with TPL-001.

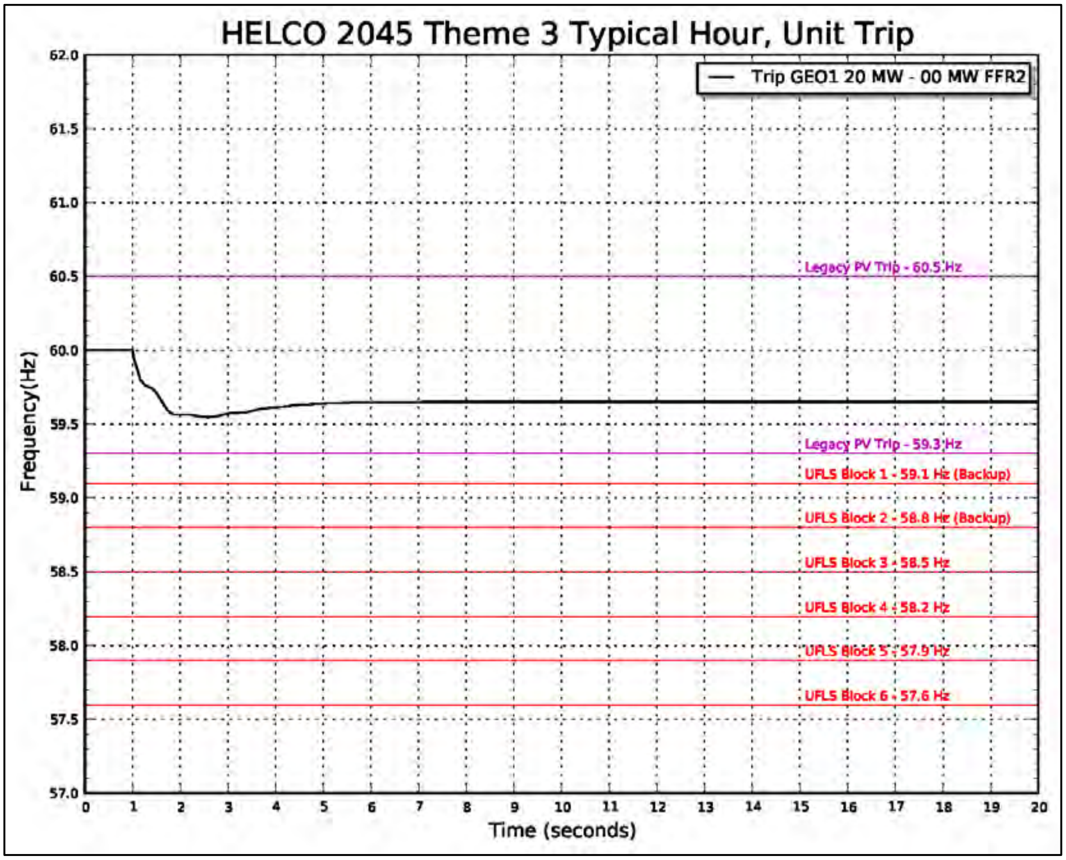


Figure O-145. Frequency Response Profile for FFR2 Typical Hour

Figure O-145shows the frequency response profile for Geothermal 1 at 20 MW for a typical hour. System kinetic energy is 699 MW-sec. No FFR2 is required because Hawaiʻi Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. No FFR2 is required because Hawaiʻi Electric Light 's UFLS scheme uses df/dt relays for Blocks 1 and 2. The df/dt UFLS capacity that was 29.7 MW. The performance of the df/dt UFLS is basically FFR at the distribution circuit level as opposed to behind the meter.

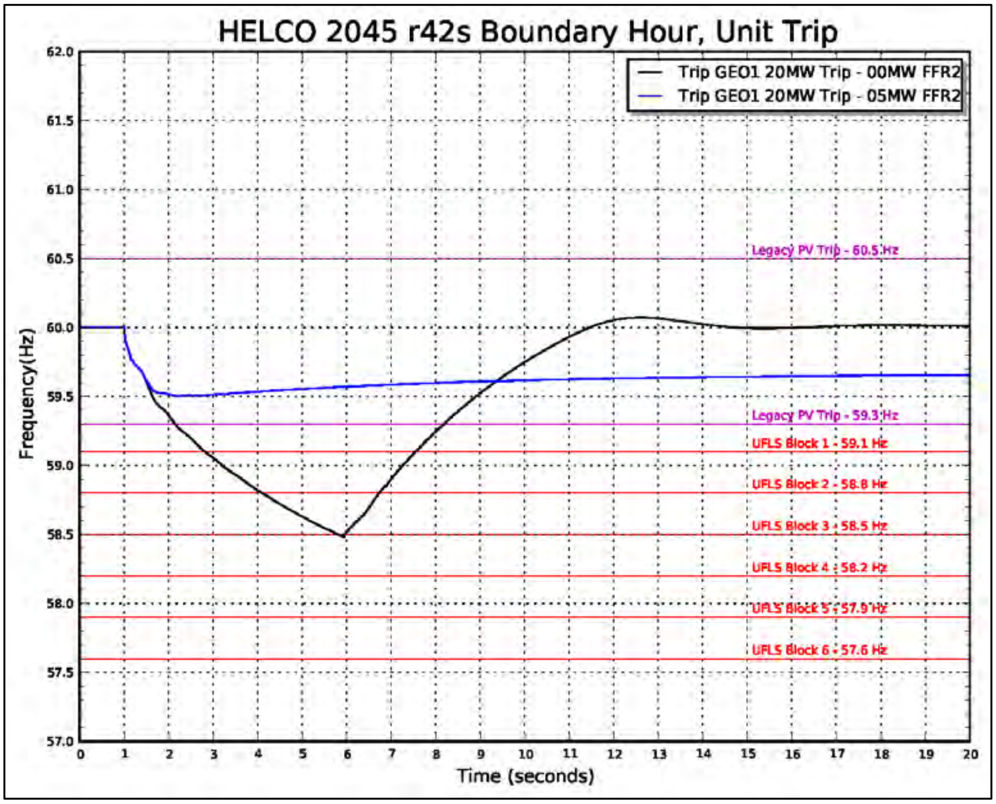


Figure O-146. Frequency Response Profile FFR2 Boundary Hour

Figure O-146 shows the frequency response profile for Geothermal 1 at 19.8 MW for a boundary hour. System kinetic energy is 610 MW-sec. Without FFR2, the frequency nadir reaches 58.5 Hz requiring 3 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW. This is in addition to the 27.2 MW of df/dt UFLS from Blocks 1 and 2.

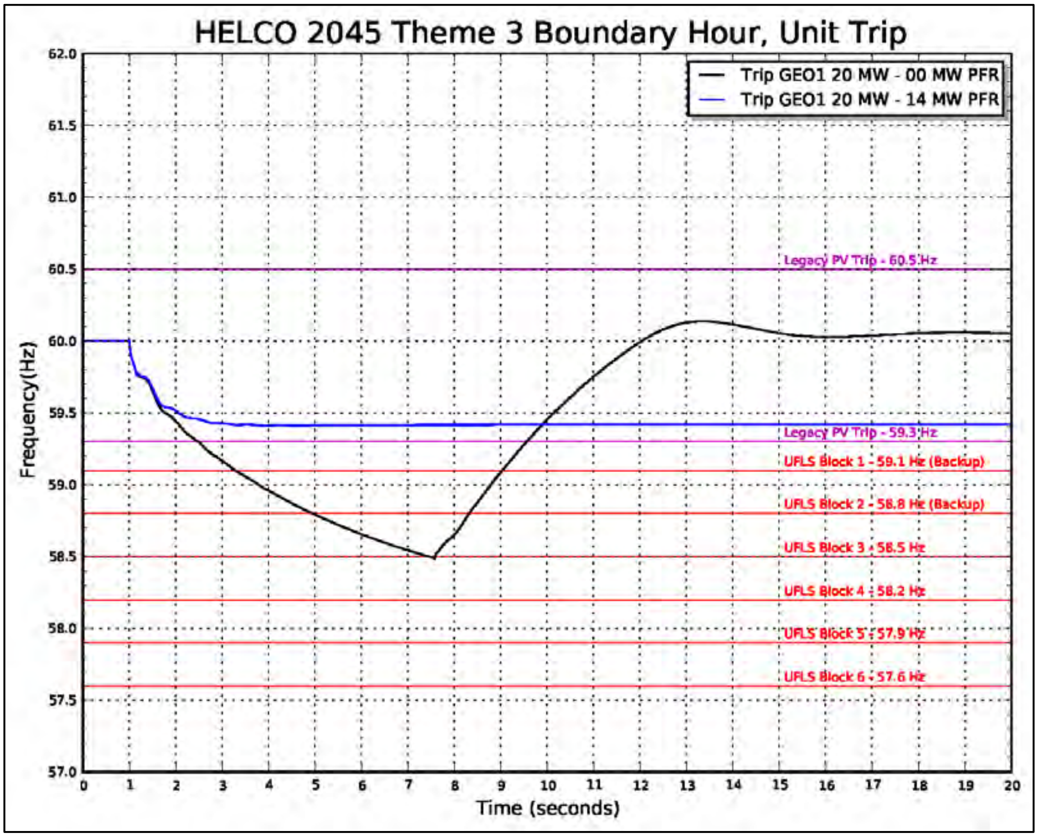


Figure O-147. Frequency Response Profile PFR Boundary Hour

Figure O-147 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 14 MW. This is in addition to the 27.2 MW of df/dt UFLS from Blocks 1 and 2.

69 kV Fault Analysis

Simulations were performed for electrical faults on the 69 kV transmission lines for the typical and boundary hours. Simulations for normally cleared faults did not produce and system stability issues.

2045 69kV Fault Delayed Clearing Analysis			
Line No Outage	**3-phase Fault Near**	**Typical Hour Condition**	**Boundary Hour Condition**
L6100	Kanoelehua	Stable	Stable
	Kaumana	Stable	Unstable
L6200	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L6300	Kilauea	Stable	Stable
	Puna	Stable	Stable
L6400	Kanoelehua	Stable	Stable
	Puna	Stable	Unstable
L6500	Kaumana	Stable	Stable
	Pohoiki	Stable	Stable
L6600	Kamaoa	Stable	Stable
	Kilauea	Stable	Stable
L6700	Kahaluu	Stable	Stable
	Keahole	Stable	Stable
L6800	Keahole	Stable	Stable
	Keamuku	Stable	Stable
L7100	Anaehoomalu	Stable	Stable
	Poopoomino	Stable	Stable
L7200	Keamuku	Stable	Stable
	Waimea	Stable	Stable
L7300	Ouli	Stable	Stable
	Waimea	Stable	Stable
L7400	Pepeekeo	Stable	Stable
	Wailuku	Stable	Stable
L7500	Kailua	Stable	Stable
	Keahole	Stable	Stable
L7600	Honokaa	Stable	Stable
	Pepeekeo	Stable	Stable
L7700	Haina	Stable	Stable
	Waimea	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable
	Puueo	Stable	Unstable
L8100	Anaehoomalu	Stable	Stable
	Keamuku	Stable	Stable
L8200	Anaehoomalu	Stable	Stable
	Mauna Lani	Stable	Stable
L8300	Mauna Lani	Stable	Stable
	Ouli	Stable	Stable
L8400	Pepeekeo	Stable	Unstable
	Puueo	Stable	Stable
L8500	Kaumana	Stable	Stable
	Keamuku	Stable	Stable
L8600	Kahaluu	Stable	Stable
	Kealia	Stable	Stable
L8700	Pohoiki	Stable	Stable
	Puna	Stable	Stable
L8800	Haina	Stable	Stable
	Honokaa	Stable	Stable
L9100	Keahole	Stable	Stable
	Poopoomino	Stable	Stable
L9200	Kaumana	Stable	Stable
	Wailuku	Stable	Unstable
L9300	Kailua	Stable	Stable
	Keahole	Stable	Stable
L9500	Kahaluu	Stable	Stable
	Kailua	Stable	Stable
L9600	Kamaoa	Stable	Stable
	Kealia	Stable	Stable

Table O-48. Summary of Results for Delayed Clearing Fault Analysis 2045

Table O-48 summarizes the results of the fault analysis. For the typical hour, 1 simulation resulted in unstable operation and 6 simulations resulted in unstable operation for the boundary hour.

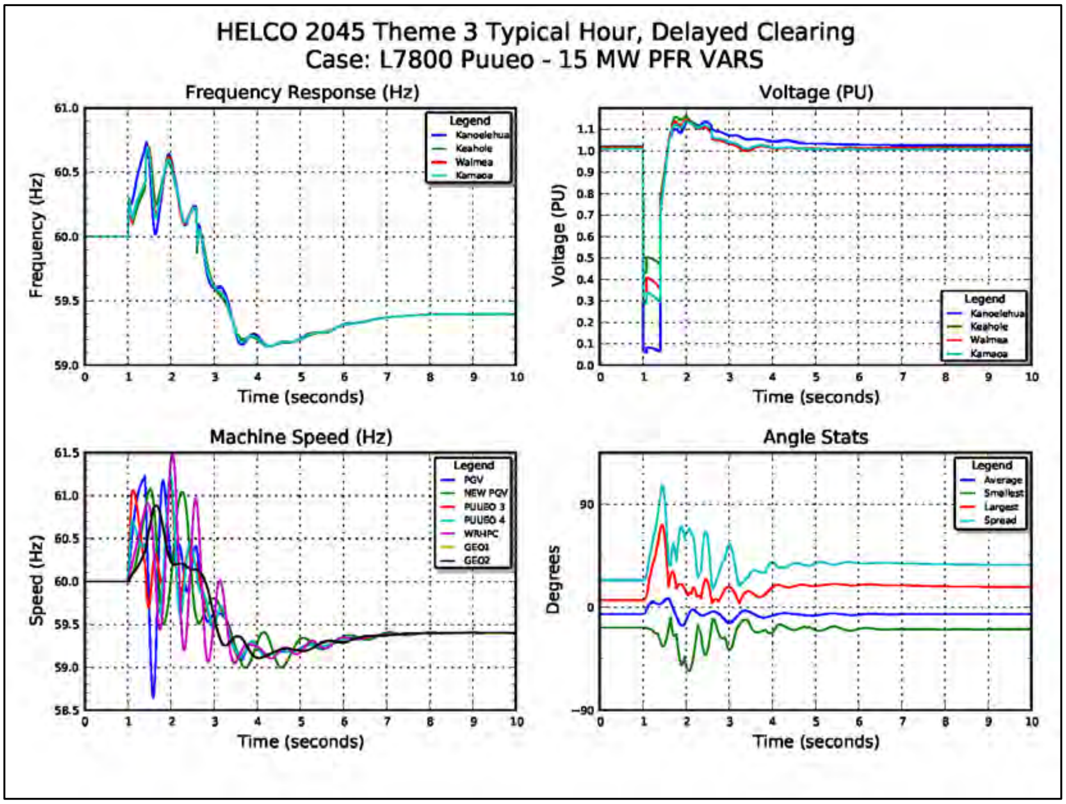


Figure O-148. System Performance to Delayed Clearing Fault

Figure O-148 shows four plots that illustrate system performance for a delayed clearing fault on the L7800 Puueo circuit for the typical hour. System voltage exceeds 1.1 PU, tripping all 109 MW of DG-PV on over voltage. Simulations were performed to determine the frequency response capacities required to bring the system into compliance with TPL-001.

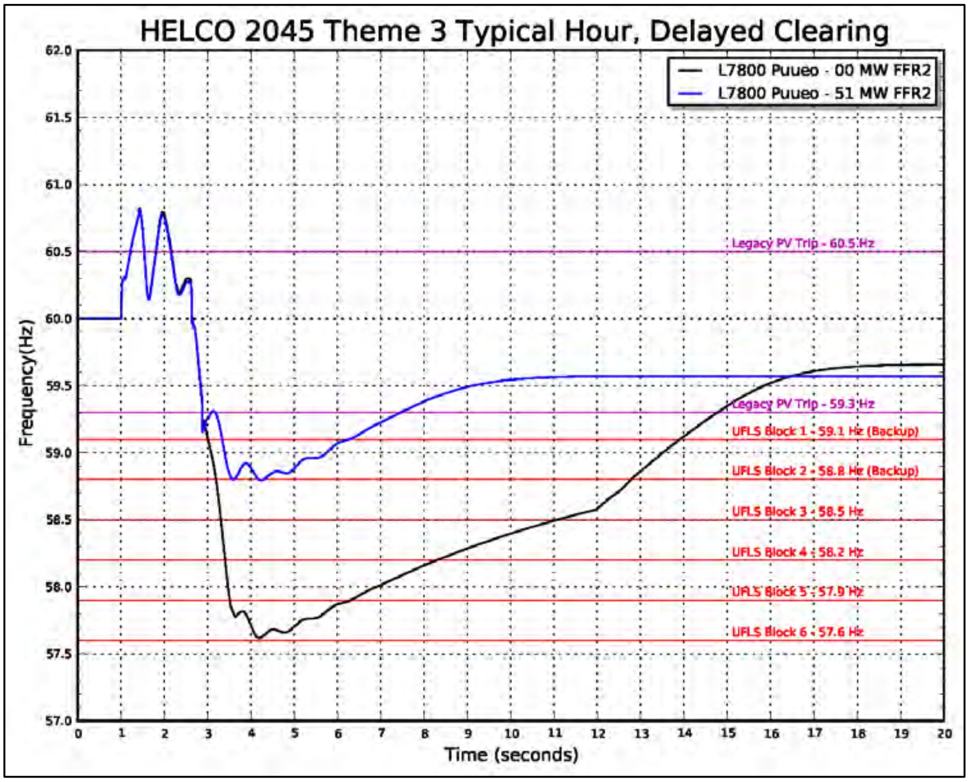


Figure O-149. Frequency Response Profile for FFR2 Typical Hour

Figure O-149 shows the frequency response profile for the FFR2 analysis. The first system peak is caused by the fault. Approximately 87 MW of DG-PV will disconnect on over voltage. System frequency begins to decay and triggers UFLS Blocks 1&2 on df/dt (29.7 MW) that momentarily stabilizes system frequency but continues to decay until the nadir hits 57.7 Hz, requiring 4 blocks of UFLS to stabilize system frequency. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 51 MW.

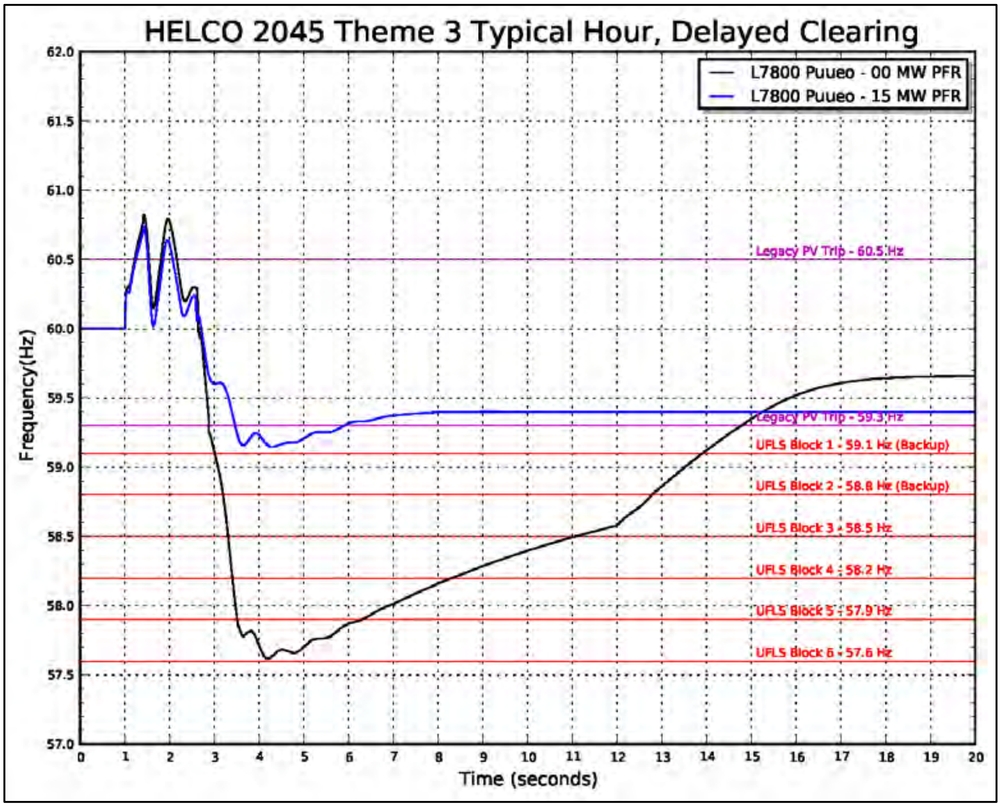


Figure O-150. Frequency Response Profile for PFR Typical Hour

Figure O-150 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 15 MW. This is in addition to the 29.7 MW of df/dt UFLS from Blocks 1 and 2

Summary

The Hawai'i system has the unique transmission covers a very large territory and has approximately 640 miles of 69 kV transmission lines. This increases the exposure to electrical faults that can cause large capacities of DG-PV to disconnect from the system because system frequency and/or voltage exceed inverter ride-through settings.

Hawai'i Electric Light is implementing a dynamic UFLS scheme to meet the requirements specified in TPL-001 that allows 15% of the system load to be shed on single loss of generation contingency events. The dynamic UFLS scheme initiates 15% load shedding on df/dt relays which provides similar frequency response from FFR2 except the load shedding is at the distribution circuit.

Compliance with TPL-001

Hawai'i Electric Light relies on its dynamic UFLS scheme to meet TPL-001. As DG-PV capacities increase, df/dt UFLS capacities will reduce and other resources must be available to stabilize system frequency. The capacity of FFR1 from a BESS to meet TPL-001 for a unit trip is 5 MW. And PFR for response to delayed clearing faults range from 5 to 15 MW.

The tables below show that the FFR1 and PFR capacities will provide frequency response reserves through 2045 for Themes 2 and 3. More detailed analyses will be conducted to support the GO7 application that will be submitted to meet the service date of 2019 for the BESS.

Frequency Response Analysis TPL-001 Compliance			
Reserve	**Theme 2**		
	2019		
	Typical HEP STCC 28 MW	**Boundary KH STCC 25 MW**	**Alternate L6100 Kano D/C Fault**
FFR2	0	5	27
FFR1	-	5	N/A
PFR	-	18	6

Table O-49. Summary of Analysis to Meet TPL-001

Table O-49 shows the results of the FFR2, FFR1, and PFR analysis. The capacity of FFR1 required to meet TPL-001 is 5 MW for the boundary hour and the capacity of PFR to the alternate hour is 6 MW.

Hawai'i Frequency Response Analysis Results									
Reserve	Theme 2								
	2020			2023			2045		
	Typical KH STCC 22 MW	Boundary HEP STCC 27 MW	Alternate L9600 Kealia D/C Fault	Typical Kamaoa WF 20 MW	Boundary Geo 18 MW	Alternate L6400 Kano D/C Fault	Typical Geo 20 MW	Boundary HEP STCC 26 MW	Alternate L8700 Puna D/C Fault
FFR2	0	14	31	0	13	75	0	9	9
FFR1	-	14	N/A	-	9	N/A	-	9	N/A
PFR	-	50	6	-	48	20	-	30	4

Table O-50. Summary of Frequency Response Analysis Theme 2

Hawai'i Frequency Response Analysis Results						
Reserve	**Theme 3**					
	2023			**2045**		
	Typical Geo 20 MW	**Boundary KH STCC 22 MW**	**Alternate L9300 Kailua D/C Fault**	**Typical Geo 20 MW**	**Boundary Geo 20 MW**	**Alternate L7800 Puueo D/C Fault**
FFR2	0	7	4	0	4	51
FFR1	-	7	N/A	-	4	N/A
PFR	-	22	10	-	14	15

Table O-51. Summary of Frequency Response Analysis Theme 3

Table O-50 and Table O-51 shows the results of the FFR2, FFR1, and PFR simulations for Themes 2 and 3 respectively. The 5 MW of FFR1 from a BESS installed in 2019 will not bring the resource plans for Theme 2 into compliance with TPL-001 in 2045 without additional resources from FFR2, PFR, or more system inertia.

MOLOKA'I

State of the System

The electrical system on Moloka'i is a radial distribution system operating at a nominal 12 kV and is not under the jurisdiction of TPL-001. The guideline established for this analysis is to keep the system nadir above 56 Hz for the largest loss of generation contingency to prevent loss of DG-PV. A 2 MW contingency BESS that is owned by HNEI is scheduled for installation in 2Q2016. All analyses modeled the performance of the BESS.

2016

Production cost simulations were not performed at the time of this writing so a screening process was not performed for Molokai. Unit commitment and dispatch cases were developed based on historical data to meet the load forecast.

Unit Commitment Order	Unit Ratings							Molokai 2016 (Typical) 12/28/16 Hour 15			Molokai 2016 (Boundary) xx/xx/16 Hour xx		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PA D7	2.2	0.3	N/A	N/A	1.1	2.8	3.0	0.5	1.5	0.2			
PA D8	2.2	0.3	N/A	N/A	1.1	2.8	3.0	0.5	1.5	0.2			
PALAAU1	1.3	0.3			0.3	1.3	0.4						
PALAAU2	1.3	0.3			0.3	1.3	0.4						
PALAAU3	1.0	0.3			0.3	1.3	0.4						
PALAAU4	1.0	0.3			0.3	1.3	0.4						
PALAAU5	1.0	0.3			0.3	1.3	0.4						
PALAAU6	1.0	0.3			0.3	1.3	0.4						
PA D9	2.2	0.3	N/A	N/A	1.1	2.8	3.0						
Wind	N/A	N/A						N/A	N/A		N/A	N/A	
DG-PV	2.6	0.0						0.7	1.8		0.0		
Station PV	N/A	N/A						N/A	N/A		N/A	N/A	
Total Kinetic Energy									6.1			0.0	
Total Load									2.9			0.0	
Total Thermal Generation									1.1			0.0	
Total Renewable Generation									1.8			0.0	
Total Generation									2.9			0.0	
Excess Generation									0.0			0.0	
Total Up Regulation									2.9			0.0	
Total Down Regulation									0.4			0.0	
Legacy DG-PV	59.3Hz Capacity			0.8				59.3Hz Output		0.6	59.3Hz Output		0.0
	60.5Hz Capacity			2.0				60.5Hz Output		1.4	60.5Hz Output		0.0

Table O-52. Unit Commitment and Dispatch 2016

Table O-52 shows the unit commitment and dispatch schedule for a typical hour.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz. The Molokai system is a 12 kV radial distribution system and is not required to meet TPL-001.

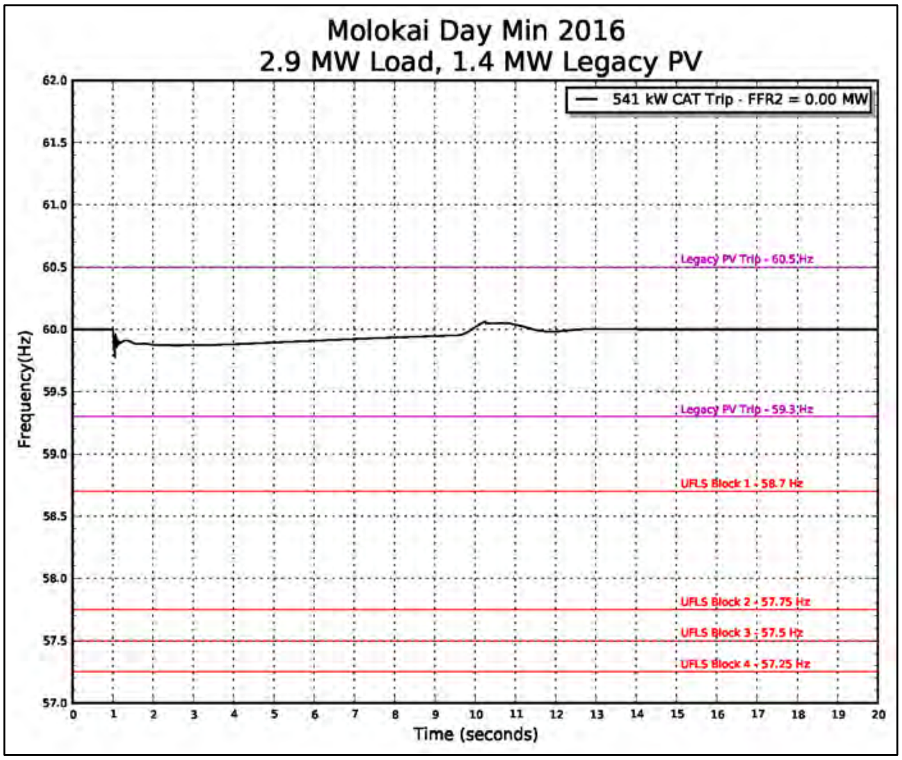


Figure O-151. Frequency Response Profile FFR2 Analysis

Figure O-151 shows the frequency response profile for a trip of Palaau Unit 7 at 500 kW. System kinetic energy is 6 MW-sec and the capacity of legacy PV that will disconnect from the system is 600 kW. Response from the 2 MW BESS limits the frequency nadir to 59.8 Hz. No FFR2 is required because the frequency nadir remains above 56 Hz.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time). Simulations for these analyses did not produce any system stability issues. There are instances of distribution voltages exceeding 1.1 PU but the 2 MW BESS is able to keep system frequency above 56 Hz.

2045

Unit Commitment Order	Unit Ratings					Molokai 2045 Sat 8/12/2045 Hour 12			Molokai 2016 (Boundary) xx/xx/16 Hour xx		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PA D7	2.2	0.6	1.100	2.75	3.025						
PA D8	2.2	0.6	1.100	2.75	3.025						
PALAAU1	1.0	0.5	0.343	1.25	0.428						
PALAAU2	1.0	0.5	0.343	1.25	0.428						
PALAAU3	1.0	0.5	0.343	1.25	0.428						
PALAAU4	1.0	0.5	0.343	1.25	0.428						
PALAAU5	1.0	0.5	0.343	1.25	0.428						
PALAAU6	1.0	0.5	0.343	1.25	0.428						
PA D9	2.2	0.6	1.100	2.75	3.025						
Sync Cond1			2.61	2.75	7.178	0.0	Sync Cond.				
Sync Cond2			2.61	2.75	7.178	0.0	Sync Cond.				
Total Wind	5					3.0					
-Wind_1	2.5	0.0				1.0					
-Wind_2	2.5	0.0				2.0					
DG-PV	4.015					0.26					
Station PV	N/A										
Total Kinetic Energy							14.355			0.000	
Total Load							3.26			0.00	
Total Thermal Generation							0.00			0	
Total Renewable Generation							3.26			0	
Total Generation							3.26			0	
Excess Generation							0.00			0	
Total Up Regulation							0.00			0	
Total Down Regulation							0.00			0	
Legacy DG-PV	59.3Hz Capacity		0			59.3Hz Output		0.000	59.3Hz Output		0.000
	60.5Hz Capacity		0			60.5Hz Output		0.000	60.5Hz Output		0.000

Table O-53. Unit Commitment and Dispatch Schedule 2045

Table O-57 shows the unit commitment and dispatch schedule for the 2045 analysis. Note that there are no synchronous units committed in Hour 12. The synchronous condensers have relatively high H-constants that provide inertia to the system as well as MVAR and system fault current.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz.

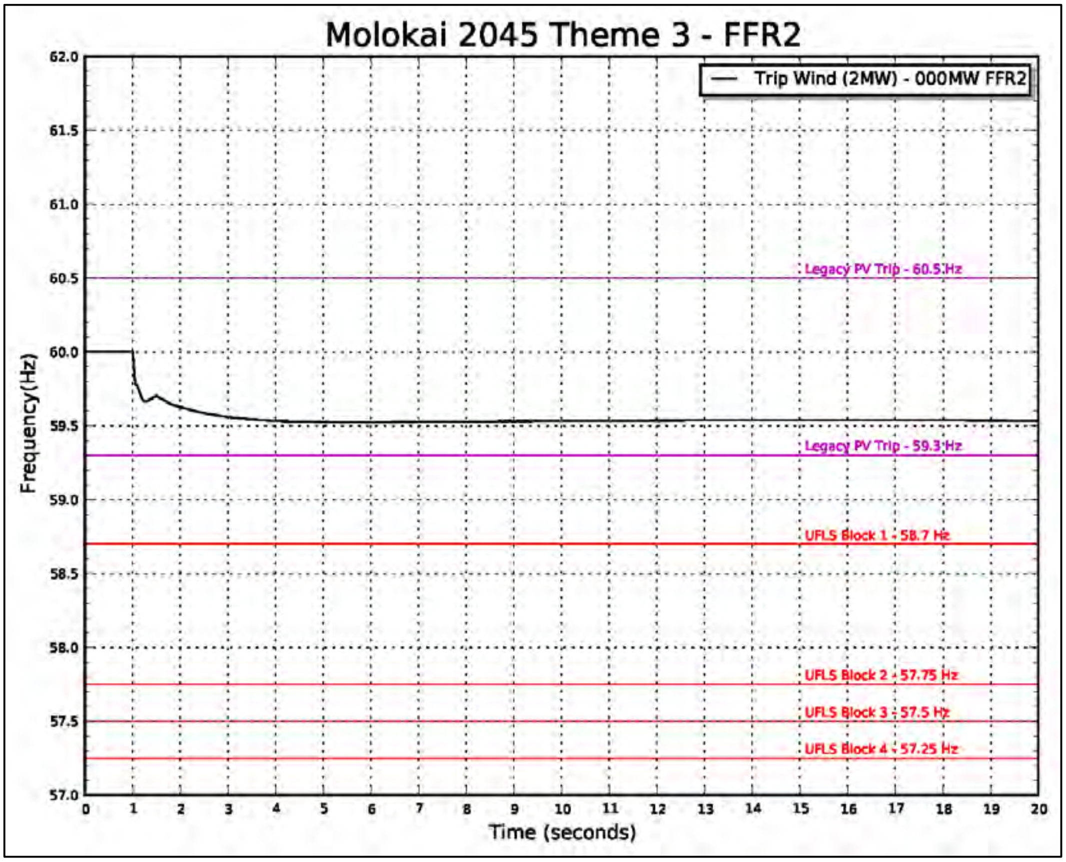


Figure O-152. Frequency Response Profile for FFR2

Figure O-152 shows the frequency response profile for the trip of a wind turbine at 2 MW output. System kinetic energy is 14.4 MW-sec due in large part to the synchronous condensers. Response from the 2 MW BESS limits the frequency nadir above 59.5 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time). Simulations for these analyses did not produce any system stability issues.

Summary

Moloka'i is a radial distribution system so the requirements of TPL-001 do not apply. The criteria established for this analysis is to keep frequency above 56 Hz so DG-PV does not trigger a cascading contingency event.

The model of the 2 MW HNEI BESS provides sufficient frequency reserves to maintain system security for loss of generation and low impedance faults for resource plans in

2045. Once the BESS is in service, the model can be tuned to simulate actual performance and system security analysis must be performed on all resource plans.

LANA'I

State of the System

The island of Lana'i has a relatively small capacity of DG-PV so system performance has not been adversely affected like the other islands. The 1 MW Lana'i Solar Farm also has a regulating BESS that helps power delivered to the system.

2016

Production cost simulations were not performed at the time of this writing so a screening process was not performed for Lanai. Unit commitment and dispatch cases were developed based on historical data to meet the load forecast.

Unit Commitment Order	Unit Ratings							Lanai 2016 (Typical) 03/16/16 Hour 12			Lanai 2016 (Boundary) xx/xx/16 Hour xx		
	Pmax	Pmin	VPO Max	VPO Min	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
L7,D-7	2.20	0.55	N/A	N/A	1.10	2.8	3.0	0.75	1.45	0.20			
L8,D-8	2.20	0.55	N/A	N/A	1.10	2.8	3.0	0.75	1.45	0.20			
LANAI1	1.00	0.50			0.34	1.3	0.4						
LANAI2	1.00	0.50			0.34	1.3	0.4						
LANAI3	1.00	0.50			0.34	1.3	0.4						
LANAI4	1.00	0.50			0.34	1.3	0.4						
LANAI5	1.00	0.50			0.34	1.3	0.4						
LANAI6	1.00	0.50			0.34	1.3	0.4						
CHP	0.83	0.00	N/A	N/A	0.34	1.3	0.4						
Wind	N/A	N/A						N/A	N/A		N/A	N/A	
DG-PV	0.66	0.00						70%	0.46		0%		
Station PV	1.00	0.00						80%	0.80		0%		
Total Kinetic Energy									6.05			0.00	
Total Load									2.76			0.00	
Total Thermal Generation									1.50			0.00	
Total Renewable Generation									1.26			0.00	
Total Generation									2.76			0.00	
Excess Generation									0.00			0.00	
Total Up Regulation									2.90			0.00	
Total Down Regulation									0.40			0.00	
Legacy DG-PV	59.3Hz Capacity			0.10				59.3Hz Output		0.07	59.3Hz Output		0.00
	60.5Hz Capacity			0.43				60.5Hz Output		0.30	60.5Hz Output		0.00

Table O-54. Unit Commitment and Dispatch 2016

Table O-54 shows the unit commitment and dispatch for 2016.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz.

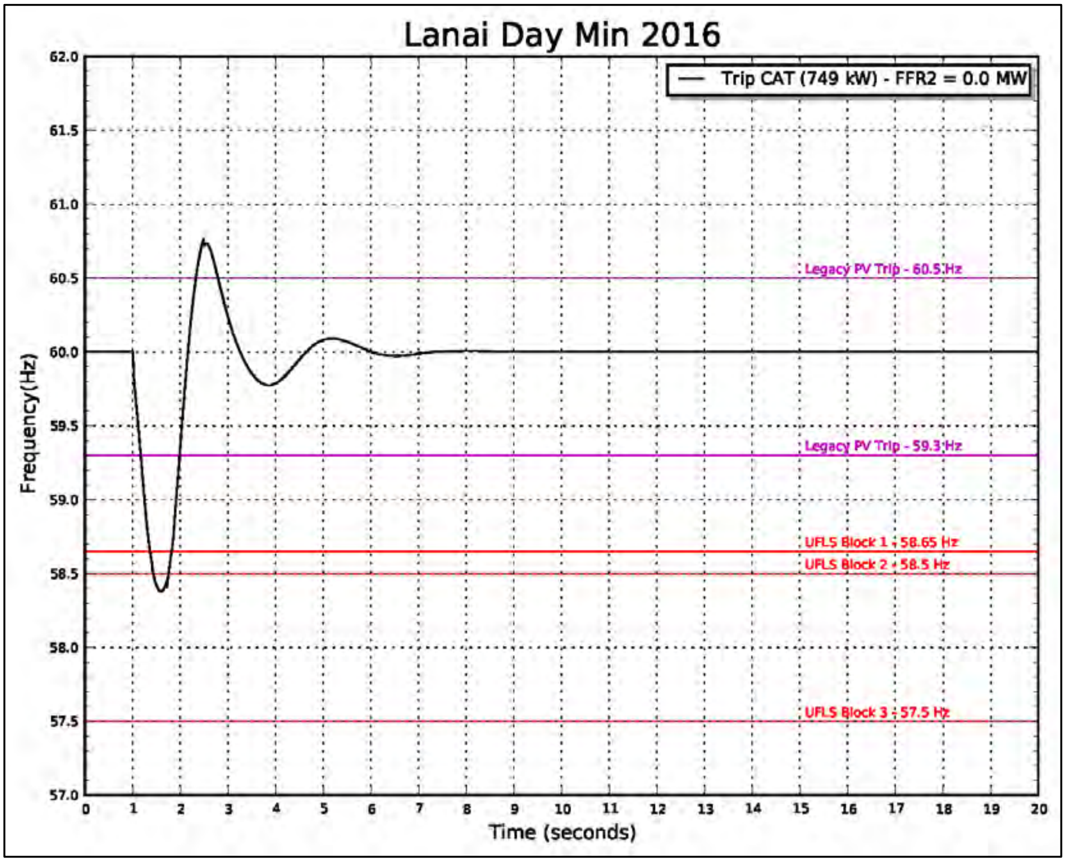


Figure O-153. Frequency Response Profile FFR2

Figure O-153 shows the frequency response profile for a trip of Miki Basin Unit 7 at 749 kW. System kinetic energy is 6 MW-sec and the capacity of legacy PV that will disconnect from the system is 70 kW. The frequency nadir remains above 56 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time).

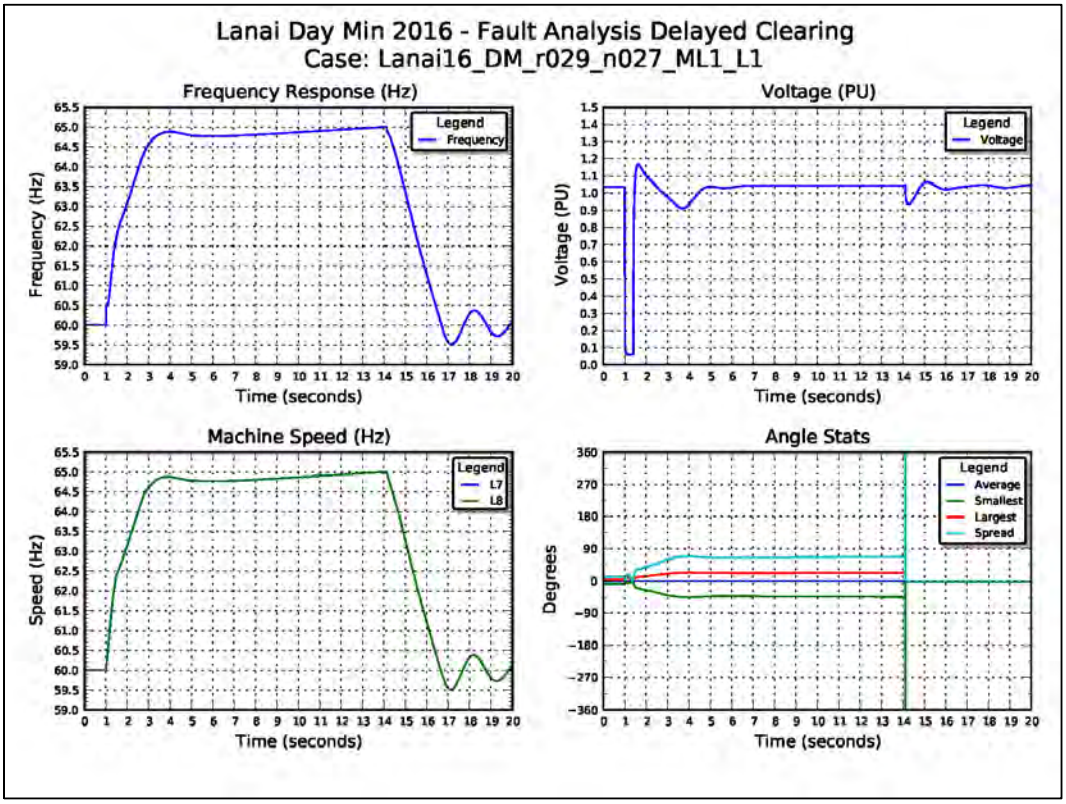


Figure O-154. System Performance to a High Impedance Fault

Figure O-154 shows four plots that illustrate system performance in response to a high impedance fault on the Miki Basin to Lanai City #1 distribution circuit. The system frequency plot shows frequency exceeds 64 Hz that will trip all DG-PV. At 65 Hz, the Lana'i Solar Farm trips so frequency is restored to 60 Hz. More in-depth analysis is required to determine mitigation alternatives.

2020

Unit commitment and dispatch cases that were developed based on historical data to meet the load forecast.

Unit Commitment Order	Unit Ratings							Lanai 2020 (Theme 1)			Lanai 2020		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
L7,D-7	2.20	0.55			1.10	2.75	3.03						
L8,D-8	2.20	0.55			1.10	2.75	3.03						
LANAI1	1.00	0.50			0.34	1.25	0.43						
LANAI2	1.00	0.50			0.34	1.25	0.43						
LANAI3	1.00	0.50			0.34	1.25	0.43						
LANAI4	1.00	0.50			0.34	1.25	0.43						
LANAI5	1.00	0.50			0.34	1.25	0.43						
LANAI6	1.00	0.50			0.34	1.25	0.43						
CHP	0.83	0.00			0.34	1.25	0.43	0.83					
Sync. Cond.	0.0	0.0			2.60	5.00	13.00	0.00	Sync. Condenser				
Sync. Cond.	0.0	0.0			2.60	5.00	13.00						
Total Wind	3.00	0.00						0.75				N/A	
-New Wind 1	1.50	0.00						0.38	1.13	0.38			
-New Wind 2	1.50	0.00						0.38	1.13	0.38			
DG-PV	0.87	0.00						0.58					
Station PV	1.00	0.00						0.39					
Total Kinetic Energy									13.43			0.00	
Total Load									2.55			0.00	
Total Thermal Generation									0.83			0.00	
Total Renewable Generation									1.72			0.00	
Total Generation									2.55			0.00	
Excess Generation									0.00			0.00	
Total Up Regulation									2.25			0.00	
Total Down Regulation									0.75			0.00	
Legacy DG-PV	59.3Hz Capacity		0.10					59.3Hz Output		0.06	59.3Hz Output		0.00
	60.5Hz Capacity		0.43					60.5Hz Output		0.28	60.5Hz Output		0.00

Table O-55. Unit Commitment and Dispatch Schedule 2020

Table O-55 shows the unit commitment and dispatch schedule for this analysis.

Loss of Generation

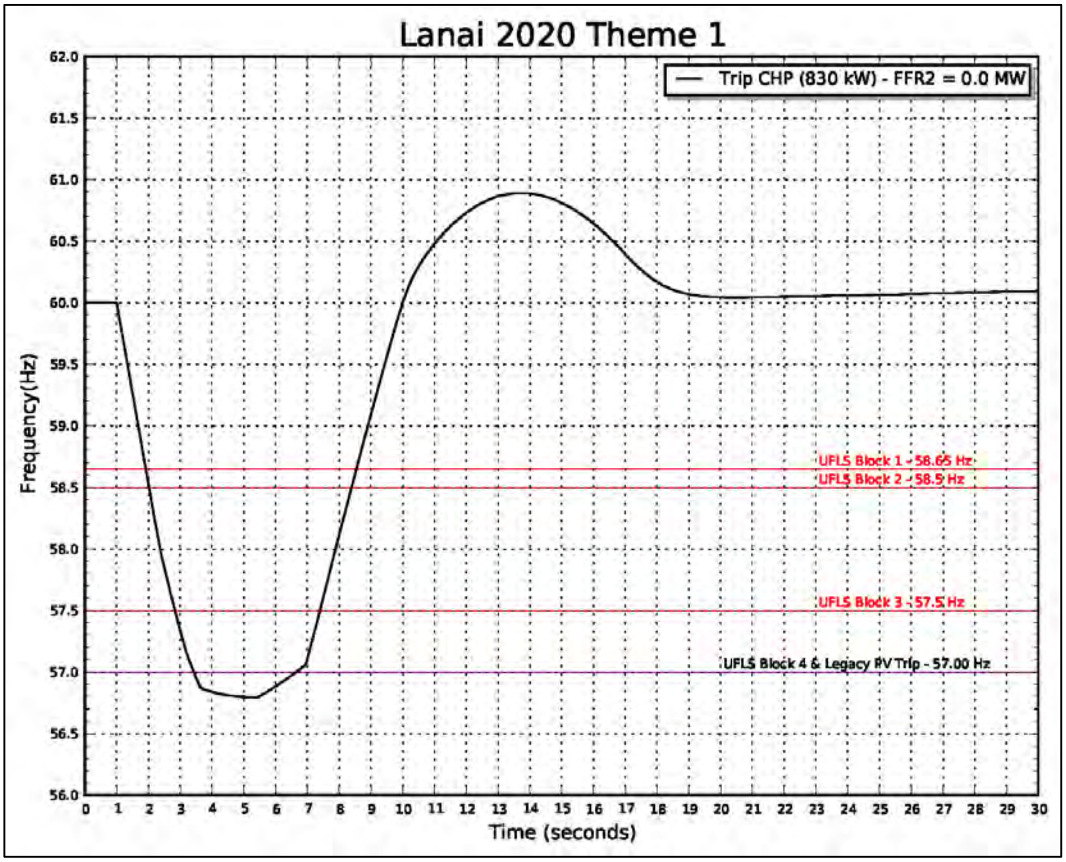


Figure O-155. Frequency Response Profile for FFR2

Figure O-155 shows the frequency response profile for a CHP unit trip at 830 kW. System kinetic energy is 13.4 MW-sec, due in large part to the synchronous condenser. The frequency nadir remains above 56 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time).

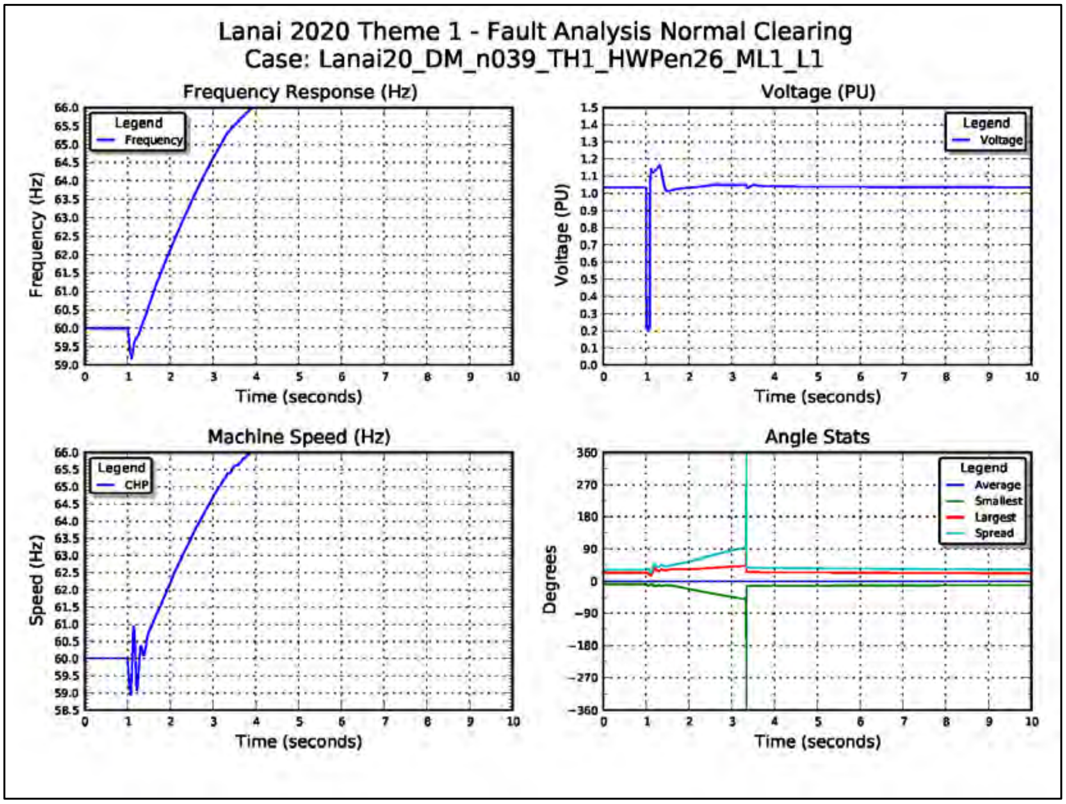


Figure O-156. System Performance Close-in Fault

Figure O-160. shows four plots that illustrate system performance in response to a close-in fault on the Miki Basin to Lanai City #1 distribution circuit. The system frequency plot shows frequency exceeds 66 Hz that will trip all DG-PV. More in-depth analysis is required to determine mitigation alternatives.

2045

Unit Commitment Order	Unit Ratings							Lanai 2045 (Theme 1)			Lanai 2045		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
L7,D-7	2.20	0.55			1.10	2.75	3.03						
L8,D-8	2.20	0.55			1.10	2.75	3.03						
LANAI1	1.00	0.50			0.34	1.25	0.43						
LANAI2	1.00	0.50			0.34	1.25	0.43						
LANAI3	1.00	0.50			0.34	1.25	0.43						
LANAI4	1.00	0.50			0.34	1.25	0.43						
LANAI5	1.00	0.50			0.34	1.25	0.43						
LANAI6	1.00	0.50			0.34	1.25	0.43						
CHP	0.83	0.00			0.34	1.25	0.43	0.83					
Sync. Cond.	0.00	0.00			2.60	5.00	13.00	0.00	Sync. Condenser				
Sync. Cond.	0.00	0.00			2.60	5.00	13.00						
Total Wind	5.00	0.00						0.00				N/A	
-New Wind 1	1.50	0.00						0.00	1.50	0.00			
-New Wind 2	1.50	0.00						0.00	1.50	0.00			
-New Wind 3	1.00	0.00						0.00	1.00	0.00			
-New Wind 4	1.00	0.00						0.00	1.00	0.00			
DG-PV	0.87	0.00						1.31					
Station PV	1.00	0.00						0.87					
Total Kinetic Energy									13.43			0.00	
Total Load									3.01			0.00	
Total Thermal Generation									0.83			0.00	
Total Renewable Generation									2.18			0.00	
Total Generation									3.01			0.00	
Excess Generation									0.00			0.00	
Total Up Regulation									5.00			0.00	
Total Down Regulation									0.00			0.00	
Legacy DG-PV	59.3Hz Capacity			0.00				59.3Hz Output		0.00	59.3Hz Output		0.00
	60.5Hz Capacity			0.00				60.5Hz Output		0.00	60.5Hz Output		0.00

Table O-56. Unit Commitment and Dispatch Schedule 2045

Table O-56 show the unit commitment and dispatch schedule for the 2045 analysis.

Loss of Generation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserves requirements to keep the system frequency nadir above 56 Hz.

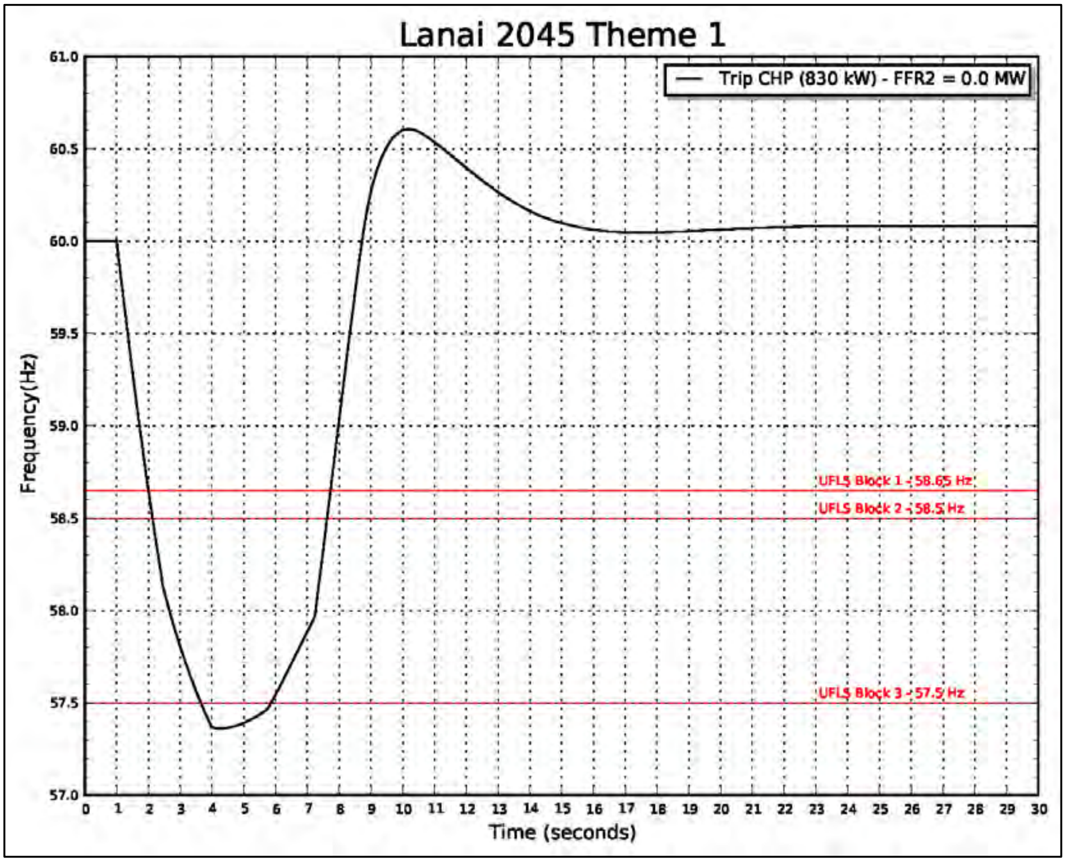


Figure O-157. Frequency Response Profile for FFR2

Figure O-157 shows the frequency response profile for a CHP unit trip at 830 kW. System kinetic energy is 13.4 MW-sec, due in large part to the synchronous condenser. The frequency nadir remains above 56 Hz so no FFR2 is required.

12 kV Fault Analysis

Simulations were performed for a close-in fault (5-cycle clearing time) and a high-impedance fault (24-cycle clearing time).

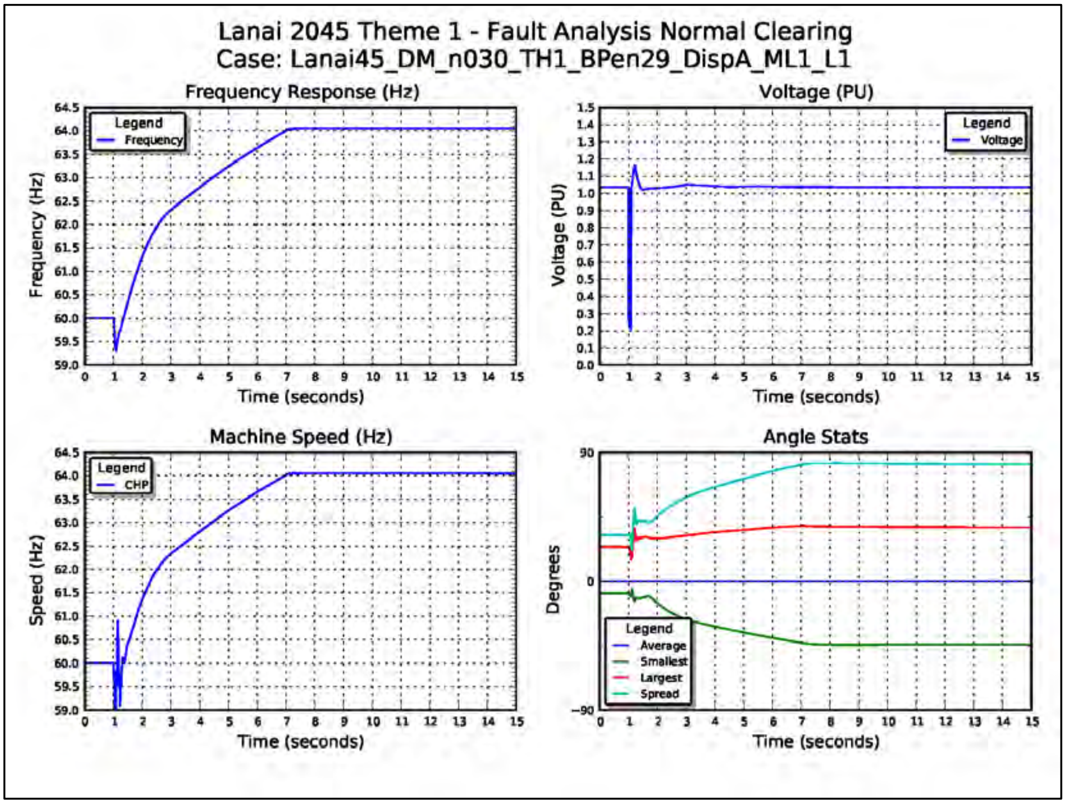


Figure O-158. System Performance to a Close-in Fault

Figure O-158 shows four plots that illustrate system performance in response to a close-in fault on the Miki Basin to Lanai City #1 distribution circuit. The system frequency plot shows frequency exceeds 64 Hz that will trip all DG-PV. More in-depth analysis is required to determine mitigation alternatives.

Summary

Lana'i is a radial distribution system so the requirements of TPL-001 do not apply. The criteria established for this analysis is to keep frequency above 56 Hz so DG-PV does not trigger a cascading contingency event.

Lana'i does not have the DG-PV penetration of the other islands but simulations indicate that both close-in faults and high impedance faults will drive system frequency above 64 Hz and exceed the new ride-through requirements of DG-PV. More analysis is required to determine mitigation alternatives.

SUPPLEMENTAL FAST FREQUENCY RESPONSE ANALYSIS

Fast Frequency Response Analysis

The FFR capacities were determined for the largest loss of generator contingency and the subsequent loss of legacy PV. For O‘ahu, this is an AES turbine trip (201 MW) and 55 MW of legacy PV. For the O‘ahu analyses, the contingency does not change because the energy from AES is significantly lower than the other fossil-fired units.

Fast frequency response one (FFR1) was modeled as a step change to full output within 12-cycles to simulate Auto-scheduling control of a battery energy storage system (BESS). In Auto-scheduling control, the BESS will receive a command to dispatch to full output on an open-breaker signal from AES or Kahe 5/6. Fast frequency response two (FFR2) was modeled as a df/dt initiated response in 30-cycles to simulate Demand Response load control technology in the near future.

The kinetic energy for each unit was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. Also, the system kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.

The simulation evaluated various system conditions to determine FFR requirements. Different unit commitment cases were analyzed to meet system load requirements at various levels of spinning reserves. The assumption is that the capacity of FFR is available for the duration of the event until the system is stable (approximately 30 minutes). Otherwise, loss of this capacity could trigger a secondary contingency event. If supplemental reserves from Demand Response are available, the duration of FFR can be reduced.

The kinetic energy for each unit was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. Also, the system kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.

Case	COMMITMENT ORDER	PMAX	PMIN	MAX TOTAL GEN	MIN TOTAL GEN	MVA BASE	H MW-s/MVA	KE MW-s	TOTAL MVA	TOTAL KE
	H-Power 1	46.0	46.0	46	46	75	2.78	209	75	209
	H-Power 2	22.5	22.5	69	69	42.1	3.41	144	117	352
	Waiau 7	83.3	23.8	152	92	96	4.44	426	213	778
	Waiau 8	86.2	24.1	238	116	96	4.44	426	309	1205
C1	AES	180.0	180.0	418	296	239	2.57	614	548	1819
C2	Kalaeloa CC1*	104.0	65.0	522	361	180.3	4.87	878	728	2697
C3	Kahe 5	134.6	64.7	657	426	158.8	4.36	692	887	3389
C4	Kahe 6	133.8	63.9	790	490	158.8	4.36	692	1046	4081
C5	Kahe 3	86.2	23.7	877	514	101	3.54	357	1147	4438
C6	Kahe 2	82.2	23.8	959	538	96	4.44	426	1243	4865
C7	Kahe 1	82.2	23.8	1041	561	96	4.44	426	1339	5291
C8	Kahe 4	85.3	23.6	1126	585	101	3.54	357	1440	5648
	Kalaeloa CC2**	104.0	0.0	1230	585	119.2	4.96	591	1559	6239
	Waiau 5	54.5	23.5	1285	608	64	4.07	261	1623	6500
	Waiau 6	53.7	23.8	1339	632	64	4.00	256	1687	6756
	CIP1	112.2	41.2	1451	673	162	4.72	765	1849	7520
	Waiau 4	46.5	23.5	1497	697	57.5	4.51	259	1907	7780
	Waiau 3	47.0	23.7	1544	721	57.5	4.51	259	1964	8039
	Waiau 10	49.9	5.9	1594	727	57	7.84	447	2021	8486
	Waiau 9	52.9	5.9	1647	732	57	7.84	447	2078	8933

*MVA and H constant based on CT and ST
**MVA and H constant based on single CT, No increase in PMIN when second CC online

Table O-57. Unit Commitment and Dispatch 2016

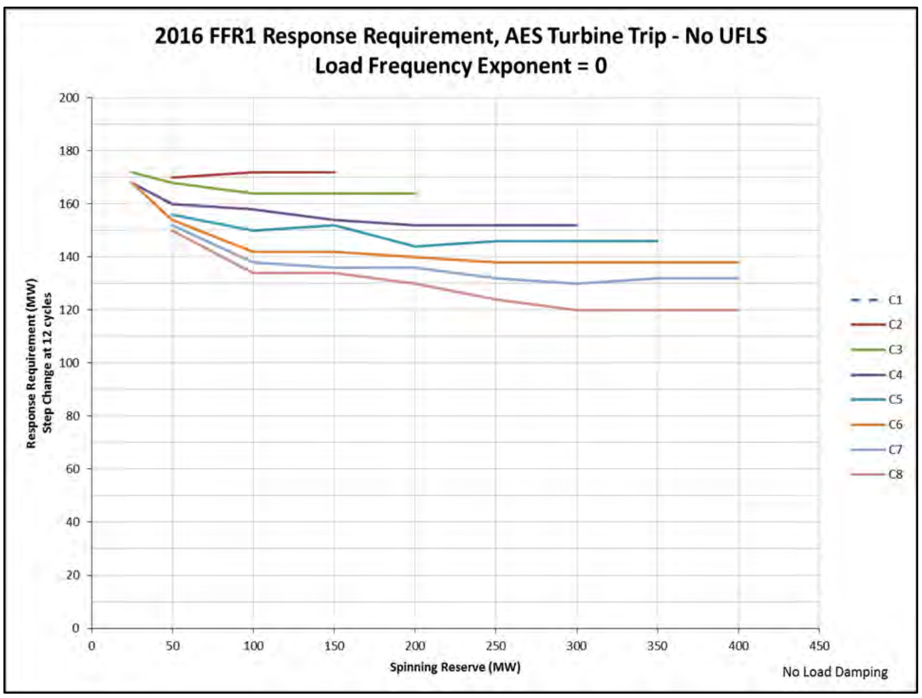


Figure O-159. System Requirements for FFR2 2016

Figure O-159 shows the system requirements for FFR1 for the different dispatch cases. The simulation for dispatch case C1 could not be solved that indicates system inertia is too low and there is no capacity of FFR1 that can stabilize system frequency for this contingency.

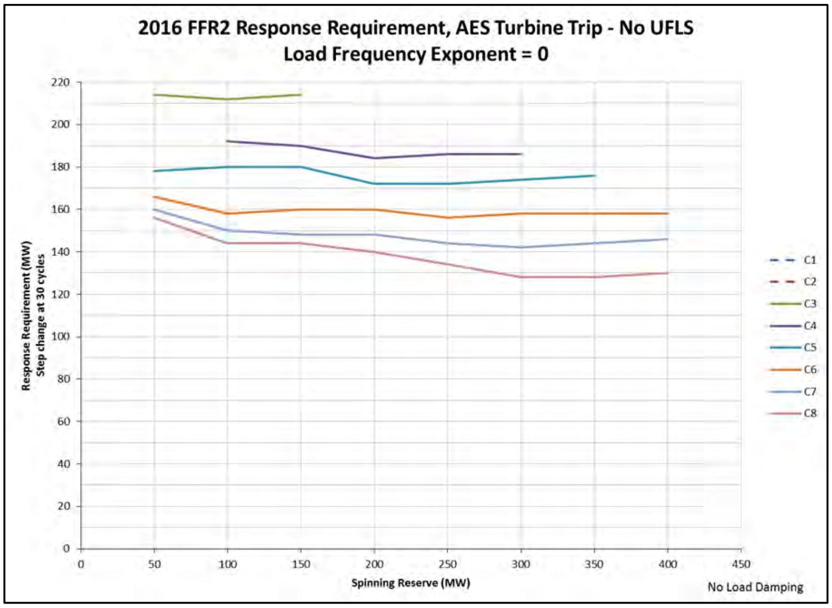


Figure O-160.

Figure O-160 shows the system requirements for FFR2 for the different dispatch cases. The simulations for dispatch cases C1 and C2 could not be solved that indicates system inertia is too low and there is no capacity of FFR2 that can stabilize system frequency for this contingency.

In the FFR1 analysis, the simulation for dispatch case C2 was able to produce a solution. Dispatch case C2 is the commitment of the Kalaeloa CT and ST which are relatively high inertia units. However, the difference in deployment times between FFR1 and FFR2 (18-cycles or 0.3 seconds) was enough to cause system instability. This illustrates how a fraction of a second can impact system security on a very low inertia system so the precision of FFR deployment is critical. Another perspective is that dispatch case C2 is operating the system close to its stability limit.

Fast Frequency Response 2 Sensitivity Analysis

Frequency response from synchronous generators is proportional to the magnitude of the contingency, whether its inertial response, primary (governor) response, exciter/field forcing, etc. Large steam turbines are better equipped to respond to an under frequency event as opposed to an over frequency event so preservation of this principle of proportional frequency response is critical to maintain system security. Over compensation of FFR2 will likely cause more problems that the initial loss of generation contingency because the capacity of legacy PV that will disconnect from the system at 60.5 Hz is higher than the capacity that disconnects at 59.3 Hz.

A sensitivity analysis was performed to illustrate this risk. The FFR2 requirement for Case 6 at 50 MW spinning reserves was applied to the lower inertia case. Tripping Kahe 5 in Case 3 results in a high rate of change of frequency (RoCoF) sufficient to initiate the df/dt trigger for 165 MW of FFR2. This can occur when units with high H-constants (e,g, Kalaeloa CT1 and CT2; or Kahe Units 5 and 6) are offline for maintenance and generation is replaced with cycling units or ICE's. The generation capacity is the same but the difference in system inertia can be drastic.

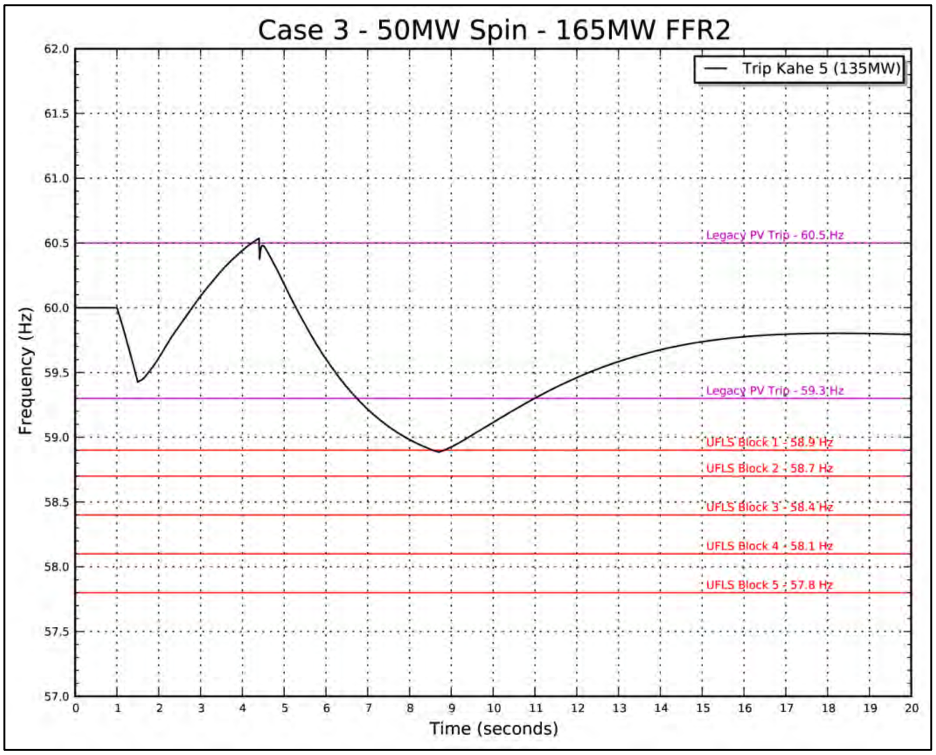


Figure O-161. Frequency Response Profile FFR2

Figure O-161 shows the frequency response profile for this simulation. Deployment of FFR2 has a dramatic impact on the RoCoF so the frequency nadir is approximately 59.4 Hz. However, this amount of load shed is significantly more that the system requires, causing system frequency to over-shoot to 60.5 Hz and tripping 74 MW of legacy PV.

Here are alternatives to ensure the correct amount of FFR2 is deployed:

- Maintain system inertia by running units in variable pressure operation
- Disable FFR2 during low system inertia conditions
- Limit the loss of generation contingency during low system inertia conditions
- Adjustable df/dt settings by the System Operator

Adjustable df/dt settings will require real-time communication and control of DR resources and full utilization of the DRMS capabilities. The initial implementation phase of the Demand Response program should add FFR2 in incremental capacities until communication infrastructure is in place to prevent over compensation.

Observations

Here are some observations about our system security work.

- Inertia, fault current, FFR and PFR when supplied in sufficient quantities by Demand Response or distributed resources can displace must-run generating units for system security.
- Distributed resources not part of an UFLS load shed scheme can provide frequency response reserves like PFR. This is true on any island.
- UFLS is a fundamental part of system security; however, DG-PV and DR reduce UFLS capacities. Demand response load shedding can be more problematic because availability of load resources are more unpredictable and a DER resource (DG-PV) with batteries. . DG-PV reduce residential load shed block capacities whereas demand response is targeting residential, small businesses, light industrial, etc. so this will reduce capacities in UFLS blocks 4 and 5 on O‘ahu which are the last line of defense to prevent system collapse (our bulk load-shed blocks).
- All islands will need “surgical” behind the meter load shedding in the future. In the interim, O‘ahu, Maui, and Hawai‘i Island should consider an intentional islanding scheme in parallel with UFLS.
- Frequency response from synchronous generators is proportional to the magnitude of the contingency event whether it's inertial response or droop response. Over compensation of FFR2 (demand response load shedding) can cause more problems than the initial contingency event because synchronous generators are better equipped to increase output than reduce or absorb energy. Therefore, implementation of DR programs must coincide with communication infrastructure and technologies that ensure we always adhere to the fundamental principle of proportional response to contingency events.
- When system inertia is high, FFR2 and FFR1 performance is equivalent (except for the proportional response issue as stated above). As system inertia is reduced, the time delay of FFR2 is long enough that no sufficient quantity of FFR2 can prevent UFLS on O‘ahu or meet TPL-001 on the other islands.
- If distributed resources are to be used for ancillary services, distribution circuit capacity must be available for this to occur.
- Managing the magnitude of the contingency is fundamental to system security. Economies of scale can reduce cost by reducing the maximum allowable contingency (e.g. 200 MW for O‘ahu).
- For Moloka‘i (today) and Lana‘i, installation of high H-constant synchronous condensers (such as old retired steam unit generators) will add more inertia than the current generating fleet of internal combustion engines. This improves system stability, adds load for PV, and provides voltage support and fault current.

TPL-001-02: TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-2 was HI-TPL-001. The standard was revised to reflect the distinct electrical systems for O'ahu, Maui, and Hawai'i Island. Lana'i and Moloka'i were removed from HI-TPL-001-02 because they are 12 kV distribution systems.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions become approved when this proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Base Year: The 2011 Balancing Authority's transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate a fault. (Source: Glossary of Terms Used in NERC Reliability Standards; Term Approved August 4, 2011.)

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet reliability requirements in Table D-58.

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady-state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Frequency Bias: A value expressed in MW/0.1 Hz that is set into the Automatic Generation Control's (AGC) Area Control Error (ACE) algorithm that allows the Balancing Authority to control system frequency.

Frequency Response: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hz (MW/0.1 Hz)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the positions identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection Systems are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System or Under Voltage Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAR), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include under-frequency or under-voltage load shedding or out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission Line: A system of structures, wires, insulators, and associated hardware that carry electrical energy form one point to another in an electric power system. Lines are operated at relatively high voltages varying from nominal 69 kV up to 138 kV.

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The facilities are divided into three island systems.

O'ahu: 2015 Data

- Daytime peak load: 1110 MW
- Daytime minimum load: 551 MW
- Nighttime peak load: 1204 MW
- Nighttime minimum load: 506 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 482.6 MVA

Maui: 2015 Data

- Daytime peak load: 180.9 MW
- Daytime minimum load: 88.6 MW
- Nighttime peak load: 206.6 MW
- Nighttime minimum load: 74.5 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 101.3 MVA

Hawai'i Island: 2015 Data

- Daytime peak load: 173.1 MW
- Daytime minimum load: not applicable
- Nighttime peak load: 191.5 MW
- Nighttime minimum load: 82.6 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 140 MVA

Effective Date: April 1, 2016

Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table D-58.

R1.1. System models must represent:

R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations.

R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

R1.2.1. Each BA system will be planned to meet the requirements of Table D-58.

R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable performance criteria defined in Table D-58.

R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table D-58.

R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response, or reserve response will withstand contingency events defined in Table D-58.

R1.2.5. The system will be planned such that all generation, reserves, regulation, and voltage control resources will withstand the most severe voltage ride-through requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table D-58.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 under-frequency load shedding. Stability will be defined such that the system will survive the first swing stability and the second swing, and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within five seconds of the initiating event.

R1.2.8. The system will be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and Table D-58.

R2. The BA must prepare a Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady-state analyses, short circuit analyses, and stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, one or more sensitivity cases must demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services.
- Typical generation scenarios including outage of the typically operated generation sources.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table D-58 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6.

- Minimum short circuit current for proper relay operation: The minimum short circuit current for each BA is specified in the Introduction.
- Maximum short circuit current interrupting capabilities of the breakers must be within the limits for proper breaker operation. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response, and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, one or more sensitivity cases must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements for steady-state, short circuit, or Stability analysis:

R2.6.1. The study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. No material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table D-58 when the analysis indicates an inability of the system to meet the performance requirements, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned system must continue to meet the performance requirements in Table D-58. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady-state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives.

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table D-58, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve the required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady-state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1 and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table D-58 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 and R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady-state or ride-through voltage limitations. Include in the assessment any assumptions made.
- Tripping of transmission elements where loadability limits are exceeded.

- Tripping of generation and other resources (including distributed resources) where ride-through capabilities are exceeded.

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady-state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table D-58 that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table D-58 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the planning assessment (as described in R2.4 and R2.5), the BA must perform the contingency analyses listed in Table D-58. The studies must be based on computer simulation models using data provided in R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table D-58 based on the Contingency list created in R4.4. For planning events P1 through P4:

R4.1.1. No generating unit can pull out of synchronism.

R4.1.2. Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.

- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-through capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators, and power flow controllers.

R4.4. Those planning events in Table D-58 that are expected to produce more severe system impacts on its portion of the system must be identified and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table D-58 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA shall have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, transient voltage response, transmission facilities overloading criteria, and dynamic stability criteria (voltage and frequency). For transient voltage response, the criteria shall at the minimum specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA shall define and document, within their Planning Assessment, the criteria or the methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding.

Planning Events

Planning Event	Initial Condition	Event	Non-Consequential Load Shed			UFLS or UVLS		
			O'ahu	Maui	Hawai'i Island	O'ahu	Maui	Hawai'i Island
P0: No Contingency	Normal system N-1 Maintenance N-2 Maintenance	None	n/a	n/a	n/a	None	None	None
P1.1: Loss of One Generating Unit	Normal system	Unit Trip Bus Fault	None	None	None	None	15%	15%
P.1.2: Loss of One Transmission Element	Normal system	SLG, 2Ø, 3Ø, Breaker Fail	None	None	None	None	None	None
P2.1: Loss of Two Generating Units	Normal system	Unit Trip Bus Fault	tbd	tbd	tbd	tbd	tbd	tbd
P2.2: Loss of Two Transmission Elements	N-1	SLG, 2Ø, 3Ø, Breaker Fail	None	tbd	tbd	None	tbd	tbd
P3.1: Loss of Multiple Generating Units	Normal system	Loss of Combined Cycle unit	tbd	tbd	tbd	tbd	tbd	tbd
P3.2: Loss of Multiple Transmission Elements	N-2	SLG, 2Ø, 3Ø, Breaker Fail	tbd	tbd	tbd	tbd	tbd	tbd
P4: Catastrophic Event	Normal system	Loss of Generating Station Loss of Transmission Corridor	tbd	tbd	tbd	tbd	tbd	tbd

Table D-58. Transmission Performance Requirements

Measures

M1. The BA must provide evidence, in hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence (such as electronic or hard copies) that it has prepared an annual Planning Assessment of its portion of the system in accordance with R2.

M3. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R3.

M4. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R4.

M5. The BA must provide dated evidence (such as electronic or hard copies) of the documentation specifying the criteria for acceptable system steady-state voltage limits, post contingency voltage deviations, and transient voltage utilized in preparing the Planning Assessment in accordance with R5.

M6. The BA must provide dated evidence (such as electronic or hard copies) of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with R6.

Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority: Hawai‘i Public Utilities Commission (Commission) or its designee.

C1.2. Data Retention: The BA must retain data or evidence to show compliance as identified unless directed by the Commission (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with R1 and M1.
- The Planning Assessments performed since the last compliance audit in accordance with R2 and M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R3 and M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R4 and M4.
- The documentation specifying the criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with R5 and M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions (such as cascading, voltage instability or uncontrolled islanding) in support of its Planning Assessments since the last compliance audit in accordance with R6 and M6.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

C1.3. Compliance monitoring and enforcement processes:

- Compliance Audits: The Commission (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-certifications
- Spot checking
- Compliance violation investigations
- Self-reporting
- Complaints

C2. Levels of non-compliance for R1 and M1:

C2.1. Level 1: The BA's system model failed to represent one of the requirement in R1.1.1 through R1.1.5.

C2.2. Level 2: The BA failed to meet all the requirements of C2.1 Level 1.

C3. Levels of non-compliance for R2 and M2:

C3.1. Level 1: The BA failed to comply with R2.6.

C3.2. Level 2: The BA failed to meet all the requirements of C3.1 Level 1.

C4. Levels of non-compliance for R3 and M3:

C4.1. Level 1: The BA did not identify planning events as described in R3.4 or extreme events as described in R3.5.

C4.2. Level 2: The BA failed to meet all the requirements of C4.1 Level 1.

C5. Levels of non-compliance for R4 and M4:

C5.1. Level 1: The BA did not identify planning events as described in R4.4 or extreme events as described in R4.5.

C5.2. Level 2: The BA failed to meet all the requirements of C5.1 Level 1.

C6. Levels of non-compliance for R5 and M5:

C6.1. Level 1: not applicable.

C6.2. Level 2: The BA does not have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, or the transient voltage response for its system for R5 and M5.

C7. Levels of non-compliance for R6 and M6:

C7.1. Level 1: not applicable.

C7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in R6 and M6.

P. Consultant Reports

Three consultants worked in concert with the Companies to perform the modeling and analyses required to develop our Preferred Plans. We then compared their results to ours to determine how closely aligned they were.

Ascend Analytics ran their PowerSimm Planner model; Energy and Environmental Economics (E3) ran long-term case development through their RESOLVE program; Energy Exemplar ran PLEXOS for power systems.

ASCEND ANALYTICS: POWERSIMM PLANNER

Ascend created a pair of expansion plans for analysis. These plans were conceived with the objective of reaching the RPS goas purely with wind, solar, and battery assets. Two alternate strategies were used to meet these targets: strategic and aggressive. The strategic plan builds renewables at a deliberate pace, calculated to meet the RPS requirements exactly in each of the target years: 30% renewable energy in 2020, 40% in 2030, 70% in 2040, and 100% in 2045. Since the targets increase the most in the later years, the strategic plan starts slow, and builds from there. The aggressive plan is an inversion of the strategic. It builds rapidly in the early years, vastly exceeding the RPS targets, and slows down in later years, eventually reaching the 100% target in 2045. The early presence of renewables allows this plan to enjoy lower exposure to fuel price risk, but this added security comes at a high cost.

Figure P-1 and Figure P-2 show the renewable generation levels for the strategic and aggressive plans.

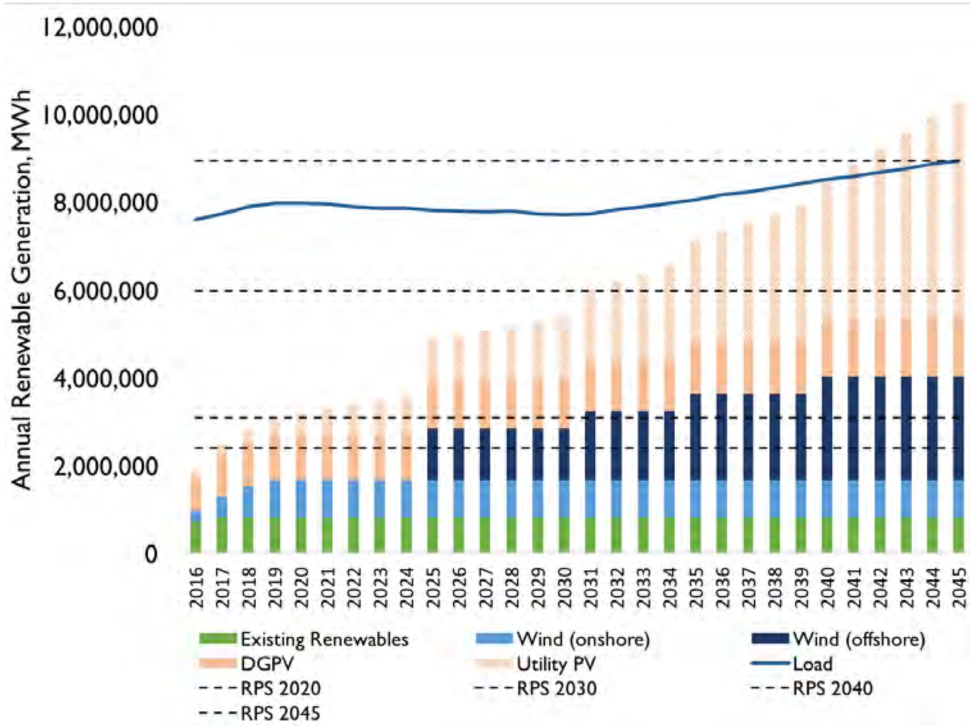


Figure P-1. Renewable Generation, Strategic Plan

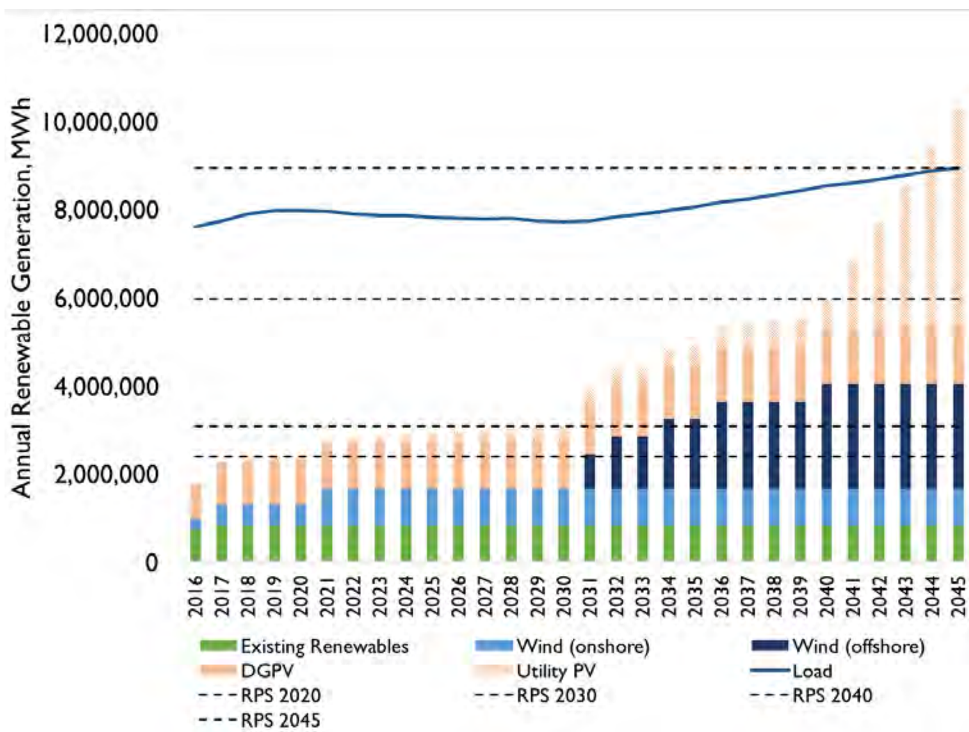


Figure P-2. Renewable Generation, Aggressive Plan

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

The heavy presence of renewable resources, particularly solar, in both plans results in large amounts of dumped energy during the day, when solar generation far exceeds demand. In addition, their intermittent nature means that, even when present in large amounts, renewables are still often unable to serve load on their own. The two problems share a common solution in batteries. The right amount of load-shifting battery storage can be used to capture over-generation during peak hours and provide energy when wind and solar resources are silent. By building batteries at a rate proportional to the growth of renewables, the strategic and aggressive plans avoid the problem of over- and under-production and provide a reliable system. Because the aggressive plan builds renewables early, its need for load-shifting comes much sooner than in the strategic plan. As battery costs are expected to continue to decline over the next 30 years, this leaves the aggressive plan in the disadvantageous position of building batteries soon, before it makes economic sense to do so. Ascend's results show that what the aggressive plan gains in fuel savings, it loses by building batteries too early.

Figure P-3 illustrates this point. It shows the net present value (in 2016 dollars) of all relevant costs associated to the strategic and aggressive plans. The costs considered include fixed and variable generation costs, the capital costs of building new renewables, and capital costs of building batteries. Figure P-3 also includes a risk premium factor, which measures each portfolio's exposure to market risk. The risk premium can be thought of as a reasonable worst-case scenario; a portfolio may exceed its average cost, but would not be expected to exceed the risk premium. The aggressive portfolio carries lower risk and generation costs, but pays with greatly increased capital costs.

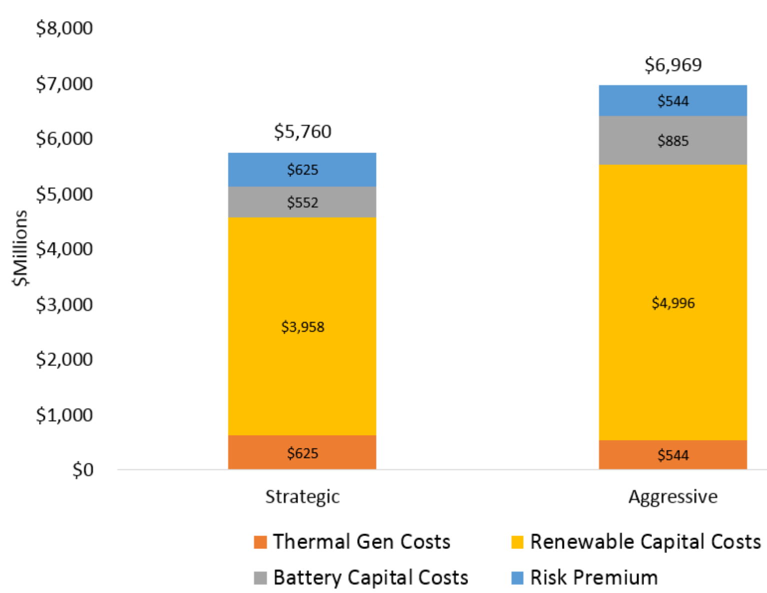


Figure P-3. Net Present Value of Portfolio Costs

E3: RESOLVE

E3 finds that for the fuel cost assumptions, investment in LNG is more cost effective than the alternative fuel oil case in 2030. This is contingent on the cost of LNG supply infrastructure remaining as assumed (including, for example, storage, piping, and delivery terminal, being less than $15 Million per year in the low fuel scenario, and less than $260 Million per year in the high fuel scenario).

HECO PSIP – Investigation of Least Cost Policy Decisions to Achieve Hawaii's RPS Goals

Contents

Executive Summary

HECO hired Energy and Environmental Economics (E3) to develop long term analysis for PSIP support based on their extensive experience in developing software and long-term planning scenarios in both California and New York as well as their our work in Hawaii. The study tests whether HECO's "least regrets" short term investment decisions are robust under a variety of different policy cases and fuel and technology price forecast uncertainty. In particular, E3 was asked to test the robustness of HECO's proposal to invest in LNG facilities as an early step in their effort to develop a 100% Renewables Portfolio Standard (RPS) compliant plan. E3 tested the decision to invest in LNG under each of the forecasted fuel price trajectories developed by HECO, and the technology costs identified in the February PSIP filing. E3 included its own estimates of battery costs and tested the sensitivity of the solution to different battery cost trajectories. This data was then fed into E3's Renewable Integration Solutions Model (RESOLVE) to develop least cost expansion plans consistent with the forecast assumptions in each case.

The key findings from the study include the following:

1. E3 investigated LNG cost effectiveness for each of the HECO created fuel price scenarios. In both the high and low fuel price scenarios, the relatively low LNG fuel price assumptions produce substantial savings over the next several decades. Our analysis estimates that the fuel savings created by an investment in LNG would produce fuel savings of approximately $112 million/year in the low fuel scenario, and $383 million/year in the high fuel scenario for the Reference case in 2030. Investments in LNG, under these fuel price assumptions, are cost effective if the required capital investments in storage, piping, and delivery terminal are less than the estimated benefits. . The robustness of this decision is not impacted by either early electrification of the transportation sector nor the decision to produce synthetic fuels for transportation. Also, because LNG is largely a direct replacement for fuel oil, the least cost decision is not impacted by the build decision of other renewable resources. This result holds true across a variety of different policy cases[1], as shown in Figure 1 below, which shows the incremental cost in cents per kWh of electricity consumed of each case we tested relative to a reference case under both

[1] Each of the policy cases investigated are described in detail in Section Case Descriptions

the low and high fuel price assumptions provided by HECO. The difference in cost between the LNG and No-LNG options is primarily driven by the large fuel price spread in all fuel price scenarios.

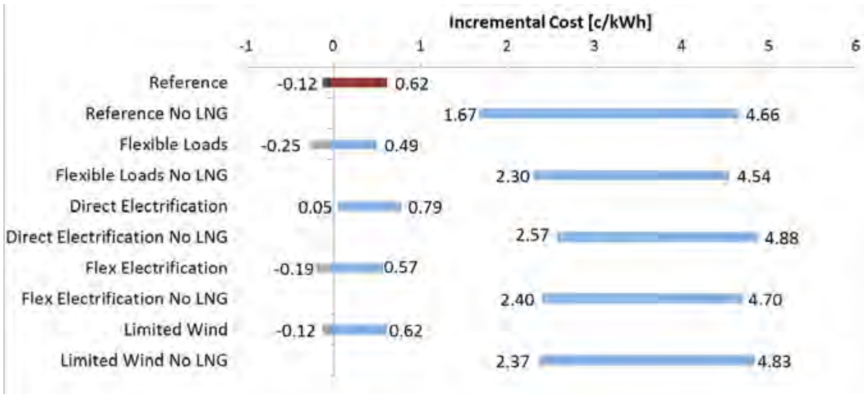


Figure 1. Comparison of operating and incremental fixed costs in 2030

2. Fuel costs, though important today for making decisions about which near-term capacity investments to make, are expected to become a minority component of the total investments that Hawaii will incur to reach its 100% RPS. The majority of expenditure through 2045 is on capital assets including PV, wind, storage, and biofuel capacity.. The fraction of operating costs as part of the total investment in new fixed assets plus variable operating costs decreases substantially over time, as shown in Figure 2. Given this relationship, the total cost of the long term plan will primarily be driven by the selection of the lowest capital cost resources over the planning period.

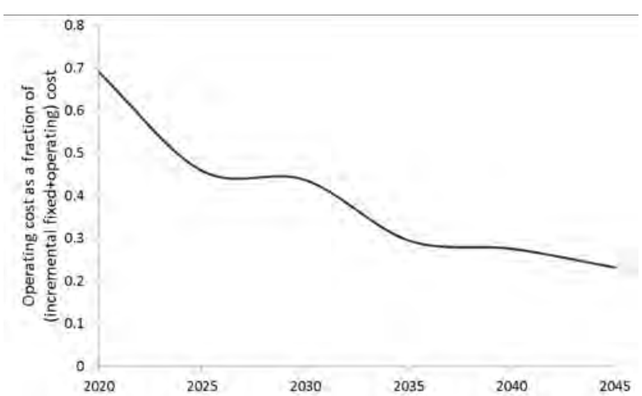


Figure 2. Operating costs as a fraction of total incremental fixed investments plus operating costs

3. The specific least cost solution in each scenario varies depending on the constraints and cost assumptions. All of the solutions, however, depend on developing a balanced portfolio of a substantial amount of high quality solar, supplemented by offshore wind when it becomes cost effective because of either solar overgeneration or land use limitations, and balanced with storage and the ability to cost-effectively curtail renewable resources.
4. While not a direct finding of the E3 study, the very high costs of fuels, land and food in Hawaii makes it imperative that Hawaii continue to focus on not just on the narrower achievement of the aggressive RPS target, but all of the 3 pillars common to all sustainable deep decarbonization pathways:

    a. Decarbonize the power sector via renewable energy or through the use of biofuels
    b. Electrify transportation and end uses in buildings
    c. Continue to invest in conservation. Because of the inherent limits on renewable potential on an island system, investment in conservation may be a critical strategy for HECO's ability to reach the 100% RPS target in 2045.

1 Introduction

HECO hired Energy and Environmental Economics (E3) to leverage the extensive planning work it has conducted in both California[2] and in New York[3] to assist utilities and state agencies comply with their aggressive clean energy standards. Given the short period of time available to study the HECO system needs under the PSIP schedule, E3's scope was limited to several key questions in informing a least-cost long-term plan for Oahu.

The E3 analysis is designed to determine how the decisions to build out the lowest-cost long-term plan might change depending on the policy direction Hawaii takes in the future to meet its RPS goals, and how the uncertainty surrounding pricing of fuels and technology affect those decisions. Presented here is a framework for evaluating those decisions to inform policy making. The long-term focus of the E3 scope emphasizes investigation of the large-scale changes in Hawaii energy policy over the time horizon to 2045, rather than the near-term detailed modeling of system operations that is covered in other efforts under the PSIP. The result is an evaluation of several different policy 'futures' under uncertain cost trajectories for technologies and fuels. Given the short study period, the framework presented here is the basis for evaluation of long-term policy pathways in Hawaii that may be expanded in the future to include refinement and greater detail on the input assumptions, and definition of additional cases to be investigated.

[2] E3 has worked in California:

- with the 5 largest utilities (PG&E,SCE, SDG&E,LADWP, and SMUD) to develop a high RPS compliance plan, developed integration models for the CAISO and the utilities (REFLEX and RESOLVE),
- developed a portfolio evaluation model (RPS Calculator) for the CPUC to be used in planning the grid and evaluating need,
- defined multiple scenarios or pathways for compliance for the Governor's office and the CA state agencies using the PATHWAYS model,
- and most recently estimated the total integration needs by pathway and portfolio using the RESOLVE model.

[3] E3 has worked in New York:

- for NYSERDA in designing a "Full Value Tariff" suitable for the goals outlined in the REV proceeding, developed a benefit cost methodology
- for the NY PSC to evaluate demand response,
- and developed a model for Consolidated Edison to design and incentivize least cost portfolios of distributed resources to meet local grid needs.

The core of the analysis is several cases that represent different policy directions in Hawaii. Each of these cases is a potential set of future system conditions that can be used to facilitate development of energy policy in Hawaii. The cases are designed to highlight the *controllable decision levers* available in formulating a robust, least-regrets plan to best handle what happens in the future. A least-regrets plan has to be robust against things that Hawaii has no control over – the things that *happen* to the islands. These include external forces such as global commodity prices and future technology pricing.

Within each case below E3 investigates a range of pricing scenarios that cover the uncertainty in both the forecast of the costs of various fuels and the costs and availability of different technologies – the things that happen to the islands. Fuel pricing sensitivities are included for oil, LNG, and biofuels. The fuel price trajectories include the "Reference," "High" and "Low" cases developed by the HECO team. Technology cost sensitivities are investigated for storage.

The specifics of each case define the constraints on how the future will evolve in Hawaii. All other decisions on system operations and resource procurement are made by the RESOLVE model to minimize costs under each fuel price and technology sensitivity. The RESOLVE model, described in the previous filing[4], is an optimal investment model that includes a representation of hourly operations to capture system needs driven by increasing renewable energy penetration. In each case, the resources selected by RESOLVE represent the overall least-cost procurement solution over the period of study from 2020 to 2045, subject to the constraints on procurement in each case.

The cases include:

1. **Reference Case.** The Reference Case extends current policy trends forward. Moving away from the Reference Case to those below will require policy action.
2. **Transportation Case.** The Transportation Case assumes policy to accelerate alternative fuel vehicle adoptions on the islands. Two variants of this case are investigated: (1) a case where electric vehicle adoption is the policy direction taken named "**Direct Electrification**"; and (2), where hydrogen and other produced fuel vehicles and infrastructure are used named "**Produced Fuels**".

[4] Power Supply Improvement Plan Update Interim Status Report, February 2016, Page C-36.

3. **Flexible Loads Case.** The Flexible Loads case assumes a greater degree of flexible loads on Oahu, reflecting policy moves towards providing the control systems for flexible load participation in balancing and the compensation mechanisms to incentivize effective use of flexible load products.
4. **Flexible Electrification.** If Hawaii could use both flexible loads from the flexible loads case and a high EV adoption policy where smart charging could also be used for load balancing, what would least cost procurement look like over time?
5. **Limited RE Potential.** Oahu is renewable energy resource constrained and will have to move beyond the resources available on the island to meet the 100% RPS requirement. The opportunities to do this include both offshore wind, which the RESOLVE model finds is selected in large amounts if its adoption is unconstrained, and imported biofuels. Just how many of these off-island resources are selected will depend on the onshore renewable energy potentials. This case investigates two variants of renewable energy constraints. The first looks at how the least cost investment decisions on Oahu change if offshore wind is limited. The second investigates how many off-island resources are required if the potential for utility scale onshore solar production is reduced from 3452 MW[5] to 600 MW, reflecting a case where solar procurement on Oahu may be limited.

[5] Addendum to Report: Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource, NREL, February 29th, 2016.

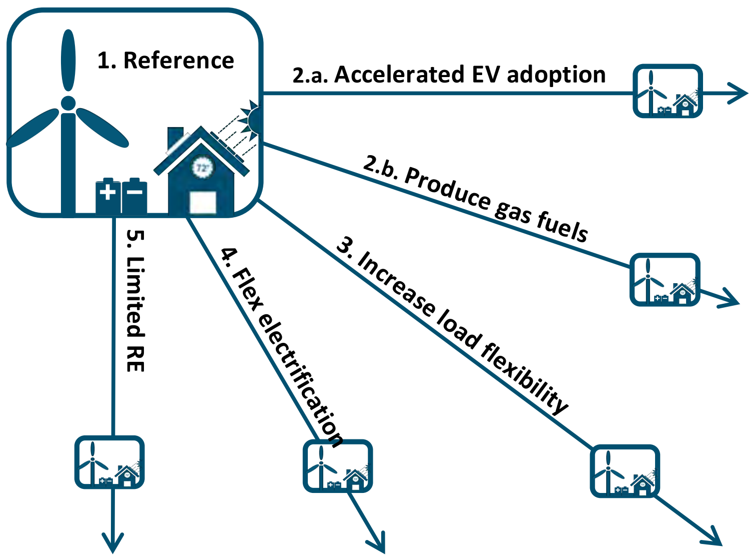


Figure 3. Cases tested against reference case

Each case is both compliant with existing RPS policy in Hawaii and seeks to maintain existing reliability. The questions E3 investigates by modeling each of the cases are described in Section 2. Each of the cases are described in detail in Section 4 where reference is made to the numerical inputs to each case that are specified in an accompanying appendix. A brief summary of findings can be found in Section 3 with a more detailed examination of results in Section 5. Section 6 presents next steps if more time was available for the study.

2 Questions Investigated

In the document "Commission's Inclinations on the Future of Hawaii's Electric Utilities", the Hawaii PUC laid out several goals for the HECO companies in planning the future grid. These included:

- Seek high penetrations of lower-cost, new utility-scale resources
- Modernize the generation system to achieve a future with high penetrations of renewable resources
- Exhaust all opportunities to achieve operational efficiencies in existing plants
- Pursue opportunities to lower fuel costs in existing power plants

These goals are clear, consistent with policy and laudable. However developing long term plans to satisfy them using the existing models and planning framework in Hawaii, and in most jurisdictions, translates into an extensive number of cases defining alternative investments. These cases will vary in their performance when tested against scenarios of different forecast assumptions. The E3 RESOLVE model can reduce the number of cases needed by identifying the least cost investments that meet future needs under a range of assumptions about what the world will look like. E3 aligned their cases with parallel HECO PSIP planning processes by using the same range of input assumptions surrounding load projections, resource cost projections, resource potentials, operating characteristics, reserve requirements, and fuel prices. Given the timeline and scope of the present study and the current, most pressing policy decisions, the findings from investigating each of the policy cases have been used to answer a focused set of questions pertinent to the PSIP. These include:

- Should Hawaii build LNG infrastructure?
- Which of the policy decisions are the most favorable?
- In each of the policy cases what are the major investment decisions and when are they made?
- What is the impact on procurement when the price of storage is varied?
- How much curtailment is included in least cost operations?
- How does the Produced Fuels case compare to Direct Electrification?

3 Summary of Findings

The results of the analysis are presented in detail in Section 5. In responding to the questions in the previous section there are a number of key findings. Where not specified, the findings below are for the cases where LNG is included. All cases are run for Hawaii state RPS targets of 40% in 2030, 70% in 2040, and 100% in 2045.

3.1 Should Hawaii build LNG infrastructure?

- E3 finds that for the HECO fuel cost assumptions, investment in LNG is more cost effective than the alternative fuel oil case in 2030. This is contingent on the cost of LNG supply infrastructure including, for example, storage, piping, and delivery terminal, being less than $112 million/year in the low fuel scenario, and less than $383 million/year in the high fuel scenario for the Reference case.

- LNG cost effectiveness is driven by the spread between LNG and fuel oil prices assumed in the HECO fuel forecasts.
- Using the HECO reference fuel scenario in the Reference Case, 150 MW of LNG are installed in 2020, another 360 MW of LNG are installed in 2025, and another 400 MW of LNG are installed in 2035. Note that this result assumes that HECO has already invested in the necessary LNG piping and storage facilities necessary to construct new LNG burning new resources.
- LNG remains in all cases in 2045 to offer contingency reserves when it is assumed to be converted to biodiesel. In the Reference Case, 400 MW of LNG remain in 2045.
- LNG is a close substitute for fuel oil, which makes this fuel switch insensitive and largely independent on the build of other resources.

3.2 Which of the policy decisions are most favorable?

- The difference in the estimated total cost to electricity consumers between the different policy decisions is small relative to the total costs of developing any of the policy compliant cases. In 2030, for example, the most cost effective policy solution on a c/kWh of load impact basis is Flexible loads. The least cost effective is the Direct Electrification case. However the difference between these two solutions in cost is only approximately 0.35 c/kWh.
- The analysis does not factor in the potential gasoline savings to customers from replacing their conventional vehicles with electric vehicles so the Direct Electrification case may be more favorable than reflected in these cases if consumer's total costs of energy (electricity plus avoided gasoline purchase) are fully captured.
- The relatively small difference in total costs between cases is a result of the relatively few options available to meet RPS requirements. Ultimately, there are not enough on-island renewable resources to meet 100% RPS, requiring relatively large amounts of either offshore wind or imported biofuel.

3.3 In each of the policy cases what are the major investment decisions and when are they made?

- The path to achieving 100% RPS requires all of the identified solar and wind potential available on the island.
- If offshore wind is available, small installations are made in 2025 and 2035, and a large installation (800 MW in the Reference case) is made in 2040. These investments are selected ahead (lower cost) of using all of the solar capacity on the island.
- Wind is invested in ahead (lower cost) of the remaining solar potential because of the reduced marginal curtailment and consequent reduced need for investment in battery storage, lowering the cost of wind relative to solar.
- Biofuels are selected even when offshore wind investment is unlimited in the model. Biofuels provide a valuable balancing function that would otherwise have to be provided by expensive batteries. Even though they can be less costly that investing in batteries, biofuel investments are still relatively expensive and happen in the 2035 to 2045 time period.

3.4 What is the impact on procurement when the price of storage is varied?

- Forecasts of storage prices are very uncertain and the storage results are very sensitive to prices. Increasing storage prices by 10% has a dramatic effect on procurement. Total storage in 2045 decreases from 1940 MW in the Reference case to 1020 MW, increases offshore wind to 2490 MW from 1060 MW, and increases biofuels to 1110 MW from 860 MW in the Reference case. In addition, total utility scale solar online in 2045 drops from the maximum potential of 3450 MW to 1300 MW.
- Across storage price variants, the build decisions between now and 2030 remain consistent. Investments in long lead time resources such as LNG that require active policy measures to implement are relatively unaffected by storage pricing. These factors make storage pricing relatively benign as a factor influencing near term planning decisions when in the context of total investment cost to reach 100% RPS in 2045.

3.5 How much curtailment is included in least cost operations?

- In the Reference, Flexible Loads, Direct Electrification, and Flex Electrification cases curtailment is approximately 20% of annual renewable energy production in 2045. The high levels of curtailment are also related to the relatively high cost of fuel. The RESOLVE model prefers building more renewable resources with higher amounts of investment in storage and curtailment because of expected higher future fuel prices.
- Curtailment shapes and levels vary significantly between whether LNG is present or not.Because future LNG prices are expected to be much lower than other fuels, curtailment across LNG cases is 3-4% in 2035 compared to the much higher10% in the No-LNG case.
- In the limited wind case, curtailment is 14% in 2040 and 10% in 2045. In 2045, all renewable potential, both onshore and offshore, is built on Oahu, resulting in an economic choice between building batteries to utilize more of the curtailed energy, or importing biofuels. Batteries are built, causing the reduction in curtailment in the final period.

3.6 How does the Produced Fuels case compare to direct electrification?

- Produced fuels scenario requires a large amount of additional load, which is expensive to meet in a resource constrained environment. As converting biofuels for hydrogen and synthetic methane fuel production is not a sensible solution due to the cost and inefficiency of such a process, relying on a substantial amount of of offshore wind would likely be needed to pursue this pathway. Exploring high renewable systems heavily dependent on wind would require additional model capability not deployable in the time frame available for this study.

4 Case Descriptions

4.1 Reference case

This is a business as usual (BAU) scenario that takes current policy trends and extrapolates them forward. This case is compliant with the RPS goals, including a high number of rooftop PV adoptions equal to the economic adoption forecasted by the HECO team. Rooftop PV is assumed controllable by 2019. Loads are relatively inflexible, with most of the additional balancing needs for renewables happening on the supply side. Electric vehicle adoption is consistent with the Hawaii EV sales target for 2030 pro-rated to Honolulu County, and held constant out to 2045. Where curtailment of both utility scale and rooftop PV systems is possible, utility scale resources are curtailed first.

The inputs below are necessary to define the starting conditions and defined annual inputs for the RESOLVE model. These can be thought of as the constraints on the system conditions expected in the future, including what resources are built over the modeling time horizon. All other investment and operating decisions on how to balance system load will be made by the RESOLVE model to minimize costs.

4.1.1 Case defining inputs

4.1.1.1 Hourly load and load forecast data

The Oahu hourly load shape from 2014 was used as a basis for the load forecast. This shape was first scaled to HECO's projected peak load in each year through 2045 (annual load growth of 1.15%). Peak load reaches 1,667 MW in 2045 from 1,170 MW in 2014. Additional transportation load was then applied to the base load shape. The annual transportation loads used were developed by Evolved Energy based on stock rollover and EV sales targets and are shown in Table 1.

Table 1. Annual transportation load (GWh) in three transportation cases.

	2020	2025	2030	2035	2040	2045
Reference	73	239	494	705	847	933
Direct Electrification	110	385	816	1,238	1,521	1,631
Produced Fuels	258	898	1,897	2,960	3,717	4,011

In the Reference and Direct Electrification cases, workplace charging availability is assumed to gradually reach 50% of all vehicles by 2045 from 10% in 2020 (Figure 4) and the electric vehicle load is shaped accordingly. The shapes used for the electric vehicle loads are based on E3's work with the PATHWAYS model in California. These normalized shapes are shown in Figure 4.

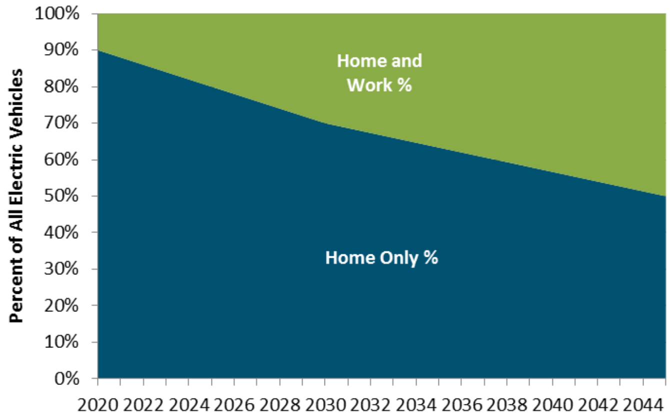


Figure 4. Percent of electric vehicles with workplace charging availability.

Figure 5. Example load shapes for Home Only and Home and Work charging.

In the flexible load sensitivity scenarios, the percent of vehicles that can be charged flexibly is increased gradually from 0% in 2020 to 50% in 2030 to 100% in 2050. In addition, we model a fraction of the heating and cooling loads on Oahu are flexible. Heating and cooling loads are assumed to be a similar fraction of total load to forecasts from California: 12% of total annual load. We assume that 1% of these loads is flexible in 2020, 10% in 2030, and 25% in 2045. These loads are then allowed to dispatched within daily constraints on energy budget, minimum hourly load, and maximum hourly load derived from the static load shapes for each end use.

4.1.1.2 Conventional generator fleet

Each scenario described here includes a treatment of Oahu's generator fleet, including currently planned additions and retirements as well as operating characteristics.

To reduce runtime, individual units are aggregated to the plant level. Table 2 shows the installed capacities assumed through 2030. All existing and planned capacity is assumed retired at the end of 2030.

Table 2. Planned installed capacities (MW).

Plant	Technology	2020	2025	2030
Waiau_ST_5to6	Steam	108	108	0
Waiau_ST_7to8	Steam	169	169	169
Waiau_CT	CT	103	103	103
Kahe_1to4	Steam	336	0	0
Kahe_5to6	Steam	268	0	0
CIP	CT	120	120	120
KPLP	Combined Cycle	208	208	208
AES	Coal	180	180	180
H-Power	Refuse	46	38	38
HIA	Biodiesel	8	8	8
Fixed_Purchase	Fixed Purchase	2	2	2
LMS100CT	CT	0	191	191
LM6000CT	CT	0	84	126
LM6000CC	Combined Cycle	0	175	175
ICE	ICE	49	98	98

The full-load heat rates assumed for each plant are shown in Table 3 below.

Table 3. Full load heat rates for Oahu generators.

Plant	Full Load Heat Rate (MMBtu/hr)
Waiau_ST_5to6	11.512
Waiau_ST_7to8	10.361
Waiau_CT	12.514
Kahe_1to4	9.896

Kahe_5to6	9.887
CIP	11.388
KPLP	9.156
AES	17.295
H-Power	47.022
HIA	10.209
LMS100CT	9.199
LM6000CT	10.006
LM6000CC	7.632
ICE	8.834

In addition, RESOLVE is allowed to build new generic generators: combined cycle (CC), combustion turbine (CT), or internal combustion engine (ICE). The full load heat rates for these generator types are shown in Table 4.

Table 4. Full load heat rates for new generators.

Plant	Full Load Heat Rate (MMBtu/hr)
CC	7,000
CT	10,006
ICE	8,834

4.1.1.3 Renewable generation

Hourly shapes for utility PV, onshore wind, and offshore wind are based on HECO's 2014 profiles. Current planned capacities of utility PV (12.4 MW) and onshore wind (99 MW) were included in all scenarios through 2030. In addition, up to 154 MW of additional onshore wind and up to 3,452 MW of additional utility PV were allowed to be built. Depending on the scenario, offshore wind potential was either left unconstrained or limited to 400 MW.

4.1.1.4 Fuel prices used here are based on HECO's projections

Three fuel price scenarios developed by HECO were used: Reference, Low, and High (Figure 6). Within each fuel price scenario, LNG prices are consistently lower than the price for LSFO and biodiesel.

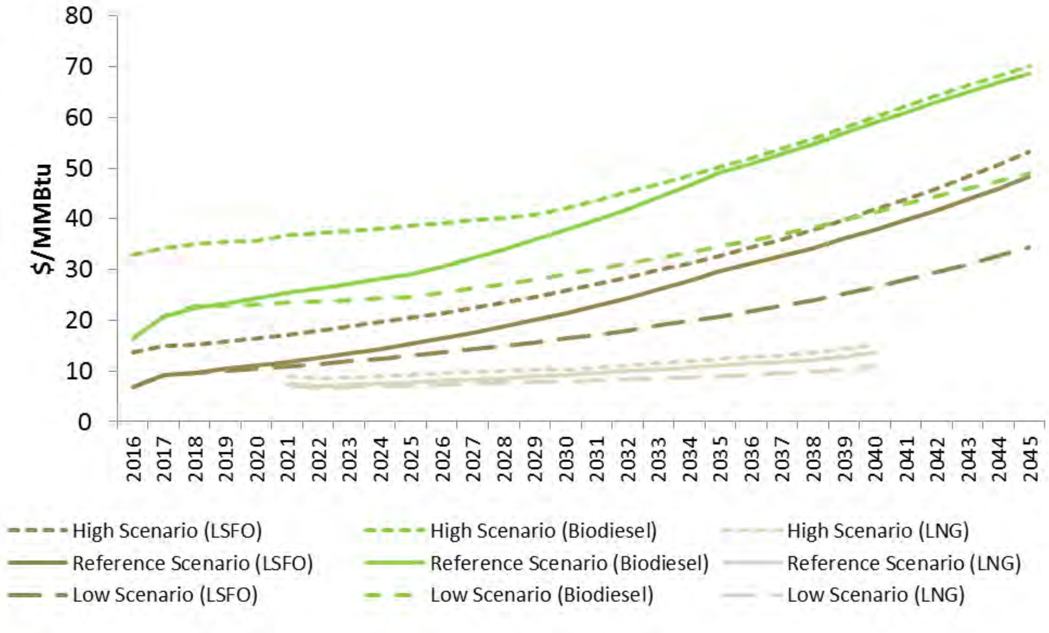


Figure 6. HECO's three fuel price scenarios.

4.1.1.5 Rooftop PV

Rooftop PV forecasted capacity through 2045 was included based on HECO's previous filing (Table 5)[6]. Additional renewables to meet the RPS requirement are selected by the RESOLVE model to find the least cost procurement plan.

Table 5. Rooftop PV capacity installations.

Date	Cumulative MW
2020	577
2025	605
2030	635
2035	672
2040	721
2045	779

4.1.1.6 Generation and Storage Costs

The capital costs for each technology are shown in Table 6. These were provided by HECO in their

Table 6.Capital costs of generation options out to 2045.

[6] Data from "Hawaiian Electric 2016 Forecast Data 20160217.xlsx" on the HECO FTP site.

$/kW (AC) Year	On-Shore Wind	Offshore Wind	Utility Scale Solar PV	Combined Cycle Gas
2016	2405	4971	2719	1727
2020	2253	4115	2201	1687
2025	2263	3356	1890	1647
2030	2181	3112	1689	1613
2035	2095	2940	1524	1589
2040	2020	2818	1376	1572
2045	1942	2703	1242	1572

Energy storage cost and performance inputs are based on a review of the literature and projections from manufacturers and developers, including:

- *Lazard's Levelized Cost of Storage Analysis – version 1.0 (*Lazard, 2015);[7]
- *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA* (Sandia National Laboratories, 2013);[8]
- *Electrical energy storage systems: A comparative life cycle cost analysis* (Zakery and Syri, Renewable and Sustainable Energy Reviews 2015);[9]
- *Rapidly falling costs of battery packs and electric vehicles* (Nykvist and Nilsson, Nature Climate Change 2015);[10]
- *2015 Greentechmedia coverage on current battery manufacturers*
- *Tesla Powerwall webpage (Last visited March 2016);*[11]
- *Capital Cost Review of Power Generation Technologies; Recommendations for WECC's 10- and 20-year studies (E3, 2014); only used for pumped hydro*[12]

Capital investment and O&M costs are annualized using E3's WECC Pro Forma tool. A 15% adder is added on top of the capital costs shown in Table 6 to take into account EPC and

[7] Available at: https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf
[8] Available at: http://www.sandia.gov/ess/publications/SAND2013-5131.pdf
[9] Available at: http://www.sciencedirect.com/science/article/pii/S1364032114008284
[10] Available at: http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html
[11] Available at: https://www.teslamotors.com/powerwall
[12] Available at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

installation costs. E3 modeled replacement of the battery pack in year 8 and replacement of the battery power conversion system in year 10. Replacement costs are assumed to be equal to the capital costs of the replacement item in the year of replacement (not including the 15% adder).

Cost and performance assumptions for energy storage technologies are summarized in the tables below.

Table 7. Energy storage performance and resource potential by technology

Charging Efficiency	Discharging Efficiency	Financing Lifetime (yr)	Replacement (yr)	Minimum duration (hrs)
92%	92%	16	8	0

Table 8. Energy storage cost assumptions

	Cost Metric	2020	2025	2030
Mid	Storage Cost ($/kWh)	238	200	183
	Power Conversion System Cost ($/kW)	247	217	204
	Fixed O&M Battery/Reservoir ($/kWh-yr)	4.8	4.0	3.7
	Fixed O&M PCS ($/kW-yr)	4.9	4.3	4.1
Low	Storage Cost ($/kWh)	175	141	121
	Power Conversion System Cost ($/kW)	158	133	119
	Fixed O&M Battery/Reservoir ($/kWh-yr)	3.5	2.8	2.4
	Fixed O&M PCS ($/kW-yr)	3.2	2.7	2.4
High	Storage Cost ($/kWh)	444	366	366
	Power Conversion System Cost ($/kW)	365	358	358
	Fixed O&M Battery/Reservoir ($/kWh-yr)	6.7	5.5	5.5
	Fixed O&M PCS ($/kW-yr)	5.5	5.4	5.4

4.1.1.7 Reserve Requirements

System security and reserve requirements, including forecasted needs. These were calculated by GE[13] and included in the previous filing.

4.1.1.8 Day Sampling and Day Weights

To reduce problem size, E3 developed a methodology for selecting a sample of days from a larger set and applying weights appropriately to reflect the long-run distributions of key

[13] Power Supply Improvement Plan Update Interim Status Report, February 2016, Page 4-21.

metrics including hourly load, hourly solar, hourly onshore wind, hourly offshore wind, and hourly net load. The load and renewable shapes from 2014 were used. In total, the scenarios presented here include 41 sampled days for each investment year.

4.2 Transportation

There are two transportation cases. The first assumes a direct electrification policy where the vehicle fleet becomes all electric by 2035. The other is a produced fuels case, where hydrogen and LNG are used as vehicle fuels. These cases are not intended to be predictive but represent maximum technical potential estimates of electrified transportation demand.

4.2.1 Direct Electrification

The direct electrification case is a variant of the Reference Case where higher amounts of electric vehicles are adopted over time, changing the forecasted electric load. The other factors of the Reference Case remain the same. The electric vehicle adoptions are determined based on forecasted aggressive EV policy impacts that cause penetrations of EVs in light-duty auto and truck subsectors to reach 100% by 2035.

4.2.1.1 Case defining inputs

- Electric vehicle sales and corresponding annual load associated with them. Stock rollover combined with a 2035 100% EV target is used to generate the load increases in each year. Adopted electric vehicles have a fixed charging profile.

4.2.2 Produced Fuels

The produced fuels case assumes there is a hydrogen and synthetic gas economy developed on Hawaii through investment in the necessary infrastructure to support it. This includes increased hydrogen and synthetic methane production capabilities and development of storage facilities. Penetrations of hydrogen fuel-cell vehicles in light-duty auto and truck subsectors reach 100% by 2035. Penetration of hydrogen fuel cell vehicles in freight truck subsector reaches 50% by 2035 due to range and duty-cycle limitations. Penetration of LNG vehicles in freight truck subsector reaches 50% by 2035. The cost of the infrastructure to produce fuels is very uncertain. In this analysis E3 does not try to quantify those costs. Instead, the incremental costs of operating the reference case system with and without hydrogen infrastructure is calculated to show the estimated incremental cost impact from all other infrastructure investments to meet the RPS goals.

4.2.2.1 Case defining inputs

- Hydrogen and LNG vehicle sales and corresponding annual load associated with the production of fuels. Stock rollover combined with a 2035 produced fuel vehicle fleet target of 100% is used to generate the load increases in each year based on the experience E3 has in modeling decarbonization for the US with its PATHWAYS model[14]. Hydrogen and LNG production is different from electric vehicles because the production of fuel is uncoupled from the use of the vehicle. This case therefore has more flexibility in how it affects load profiles: the gas production infrastructure behaves like a large battery system. However, the losses involved in producing and consuming fuels result in significantly higher load increases than the Direct Electrification case. Both the peak MWs and the quantity of produced fuel storage are key variables in sizing a system like this. The costs of this type of infrastructure are very uncertain. This analysis assumes a peak MW production of fuels of 25% of peak load as a first cut investigation into produced fuel viability.

E3 generated the annual electricity load corresponding to the Reference Case and each of the transportation scenarios using stock rollover logic. These are paired with vehicle charging characteristics in the case of EVs to develop a flexibility constrained resource from the aggregate electric vehicles. The dataset contains the following inputs:

- Vehicle stock. The forecasted vehicles of each type, in each year, and in each case.
- Final energy demand. The final energy demand of vehicles of each type, in each year, and in each case.

[14] Policy implications of deep decarbonization in the United States, November 2015, http://usddpp.org/downloads/2015-report-on-policy-implications.pdf

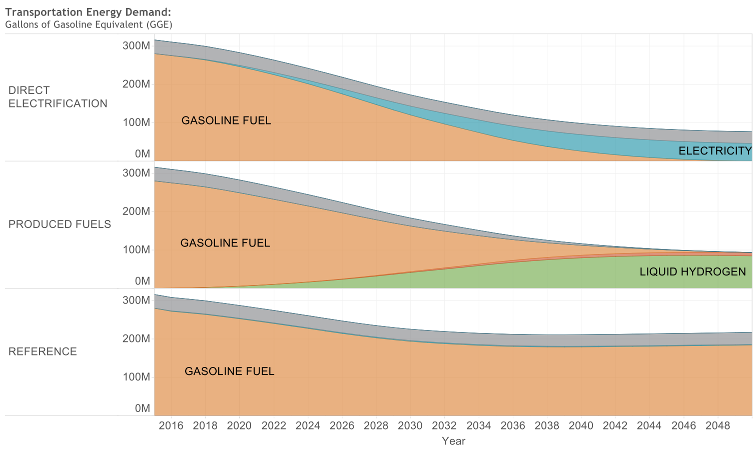


Figure 7. Transportation fuel mix under different transportation policy scenarios

- Electricity load. The change in annual load cause by vehicles of each type, in each year, and in each case.

Figure 8. The additional electric load over the Reference case in each of the transportation cases

4.3 Flexible loads

This case is a variant on the Reference Case that assumes policy incentivizing greater flexible load participation by customers. This case assumes a greater level of investment in controls infrastructure and development of tariffs or compensation mechanisms that support participation and make possible the dispatchability of demand side technologies such as space heating, space cooling, and water heating. E3 models a portion of these end-uses as flexible within constraints on total daily end-use energy demand as well as minimum hourly demand and maximum hourly demand on each day.

Load flexibility (also referred to as demand response or DR) can serve as an important resource for keeping Hawaii's electricity grid stable, resilient, and efficient while facilitating the transition to high penetration levels of renewable energy and providing economic benefits to HECO's ratepayers. HECO has already begun conducting studies on the potential of a range of end-use loads to provide various grid services such as ramping, regulating reserve, and contingency reserve. In addition, residential, commercial, and industrial end uses may be able to provide system value by shifting load to times of high renewable generation levels, making it possible to utilize renewable energy that might otherwise be curtailed. Achieving dispatchability of demand side technologies such as space heating, space cooling, and water heating would require investment in controls infrastructure and development of tariffs or compensation mechanisms that support participation. E3 uses HECO's DR potential studies as a basis to derive reasonable estimates for the portion of these end-uses that may be dispatchable.

E3 also uses end-use load profiles developed for the California State Agencies' PATHWAYS[15] project to derive operational constraints including daily end-use energy demand, minimum hourly demand and maximum hourly demand on each day. While an accurate assessment of flexible load potentials and characteristics over the next 30 years is not possible, E3 includes a treatment of flexible loads in the RESOLVE model with the goal of understanding the benefit of flexible load capability to HECO's future grid and the operational characteristics that may be most valuable.

4.3.1 Case defining inputs

- Annual flexible load technology adoptions along with parameters defining their behavior in dispatch. These are included in the attached spreadsheet titled "DR_Potentials". Included in the spreadsheet are the components needed to model different levels of flexible loads in REFLEX, including:
    - HECO's annual energy and peak demand projections by end-use
    - HECO's estimates of DR program potential
    - E3 calculations of fractions of end uses that are shiftable
    - Demand profiles by end-use developed for the California State Agencies' PATHWAYS study

[15] California State Agencies PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios, April 2015, http://www.arb.ca.gov/html/fact_sheets/e3_2030scenarios.pdf

- HECO end-use annual energy demands shaped with PATHWAYS demand profiles

4.4 Flexible Electrification

This case investigates the impact on incremental cost of meeting the RPS and the investment decisions made to get there when both flexible loads and smart charging EV policy are adopted. The combined impact of these two policies will increase the balancing capabilities of the system and reduce the need for other flexibility solutions, such as battery investments.

4.4.1 Case defining inputs

- This case is a combination of the Flexible Loads case and the Direct Electrification Transportation case with modifications. The modifications include a characterization of the flexible charging capabilities of the EV fleet, increasing the balancing capabilities of that resource.

4.5 Limited Renewables

4.5.1 Limited Wind

With plans existing for up to 1200 MW of offshore wind, this could be a valuable resource for Oahu to reach its RPS targets. There is not enough potential on the island itself to meet 100% RPS, therefore additional resources must be procured. The options considered in the previous PSIP filing include offshore wind and imported biofuels. The results from the RESOLVE model will show that if offshore wind procurement is unconstrained a significant number of MWs are selected as part of a least cost portfolio over the next 30 years in many of the E3 cases. This case investigates how the solution changes if offshore wind development is constrained.

4.5.1.1 Case defining inputs

- This is a variant of the reference case and includes a cap on the total offshore wind that can be online of 400 MW.

4.5.2 Limited Utility Scale Solar Potential

NREL recently revised down their estimate of how much utility scale solar potential exists on Oahu. In this case we explore how the build decisions are affected over the course of the planning period if utility scale solar resources are limited to 600 MW.

4.5.2.1 Case defining inputs

- This is a variant of the reference case and includes a cap on the total utility scale solar of 600 MW.

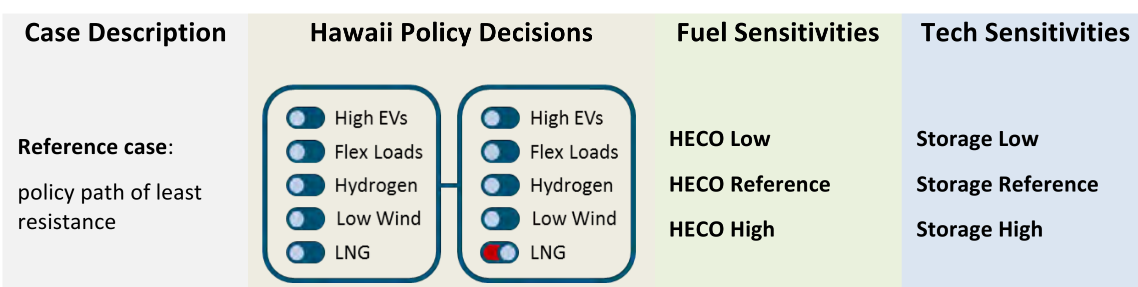
5 Results

The cases investigated are listed below in Figure 9. Each of the cases represents a set of policy decisions that could be taken by Hawaii to influence how the long term RPS goals are met. The cases all include fuel and technology price sensitivities. The fuel price sensitivities include the HECO low, reference, and high fuel price trajectories. The price of storage is also varied to determine the effect on investment decisions.

Each case is run for both the policy decision to invest in LNG and the policy decision not to. By including the evaluation of LNG in all cases, E3 focuses specifically on the near term decision facing HECO by investigating how that decision might impact the long term investments to meet Hawaii's RPS targets.

The costs reported for each case are the total annualized investment costs and variable costs related to energy production. They do not include the infrastructure costs for LNG such as storage, delivery terminal facilities etc, the cost of electric or produced fuel vehicles, EV charging and hydrogen production and storage infrastructure, existing infrastructure costs, or costs for new transmission and distribution investments.

The difference in cost between the LNG and non LNG variants can be thought of as the breakeven cost between investing in LNG infrastructure and staying with fuel oil. For the particular fuel and technology price scenario, if LNG infrastructure costs less than the difference between the two variants, then LNG investment is a cost effective decision.



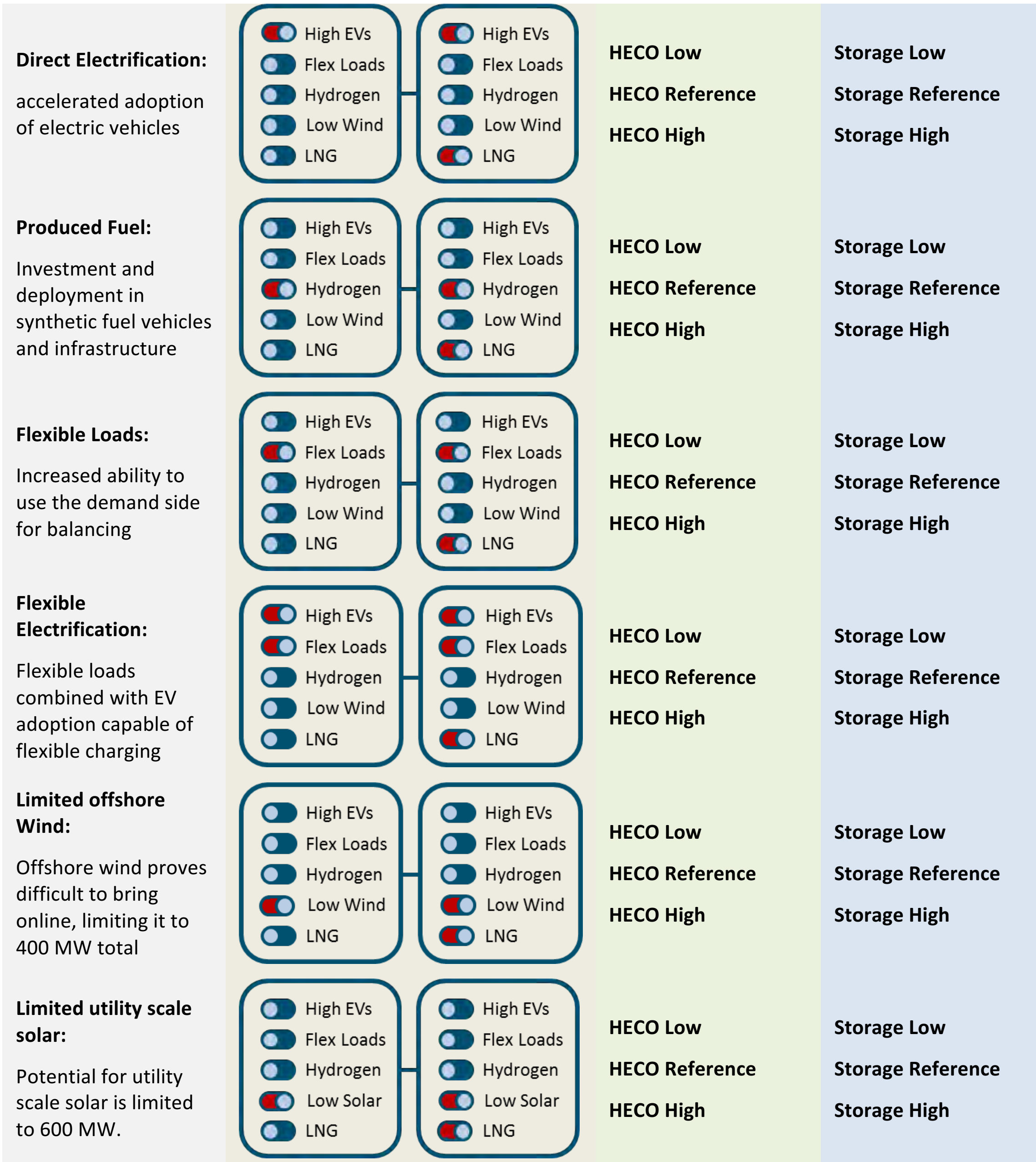


Figure 9. Case descriptions

As specified in section 2, the questions we investigate in this analysis are as follows:

- Should Hawaii build LNG infrastructure?
- How do the different policy cases rank in total cost, or impact to ratepayers, under the different fuel and technology cost scenarios?
- In each of the policy cases, what are the major investment decisions, and when are they made?

We use a 5 year time step across the modeling period from present day out to 2045. The investment decisions made in each time step represent investments determined to be made in that year or the 5 years around that year. For example, investments identified for the 2020 time step represent investments any time between mid-2017 to mid-2022.

For many of the cases presented below, LNG fueled generating capacity remains in 2045. We assume that the LNG contract ends in 2040, and that this capacity is converted to biofuels in 2045 or before to comply with the RPS targets. However, we retain the LNG designation for this capacity in the results to indicate that it is not new build, and to differentiate it from dedicated new construction biofuel generation.

In order to develop and present results in the limited time available for the study, we focused only on meeting the Hawaii state RPS targets. This allows an apples-to-apples comparison of the presented results for better understanding of the dynamics between different resource selection decisions.

5.1 Should Hawaii build LNG infrastructure?

To investigate whether Hawaii should build LNG infrastructure, E3 used RESOLVE to find the annualized operating cost and incremental investment cost of new assets for each of the policy cases and each of the HECO fuel price forecasts. These are shown in Figure 10 below for the year 2030. These costs include the investment in new LNG power plants and the operation of those plants. In every case, the LNG variant is significantly less expensive.

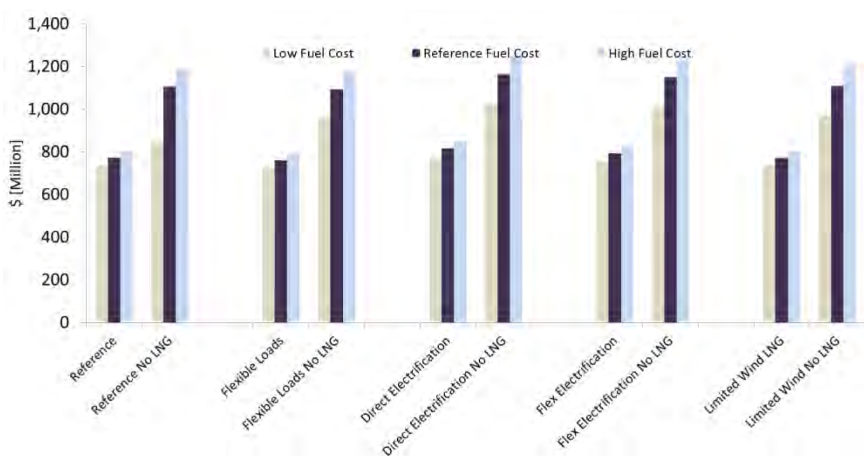


Figure 10. Total annualized fixed (incremental new investments) and operating costs in 2030

The difference in cost between the LNG and No-LNG cases is the amount that HECO can invest in LNG infrastructure, such as storage capacity, while still remaining below the cost of the alternative No-LNG case. Table 9 shows the difference in cost under each of the fuel price sensitivities. If the annualized cost of the LNG infrastructure is less than ~$112M in the low fuel price case to ~$383M in the high fuel price case then LNG is found to be cost effective for this set of assumptions in the Reference case. In the other policy cases, the low fuel cost scenario has a larger barrier to cost effectiveness for LNG.

Table 9. Annualized fixed and operating cost savings in 2030: LNG vs no-LNG case

Cost Savings $M/yr	Fuel Price Sensitivity		
Case	**Low**	**Reference**	**High**
Reference	112	334	383
EV	242	331	384
Flexible Loads	247	348	401
Flex Electrification	255	356	404
Limit Wind	236	336	399

These benefits depend on the spread between LNG and fuel oil. The decision to invest in LNG or not is therefore strongly tied to the HECO fuel forecast assumptions. Figure 11 shows the incremental capacity additions and retirements in each of the periods studied. In the LNG case, the first MWs of LNG capacity are selected in 2020. That capacity is then expanded in 2025 and 2035. The long term projection of relative fuel prices is therefore important in deciding whether to invest in LNG or not.

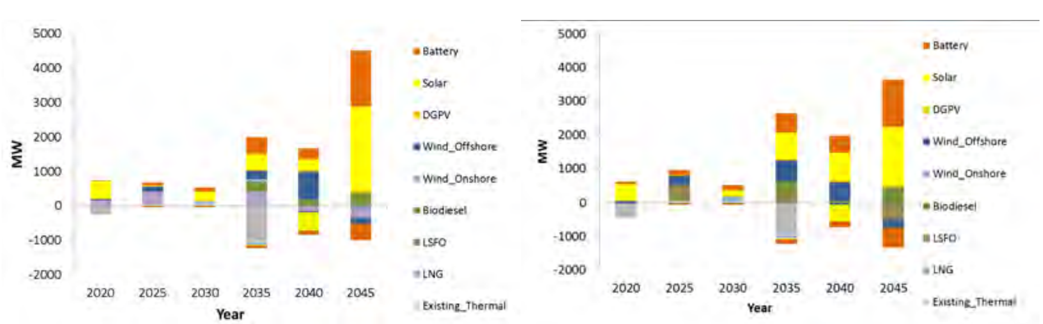


Figure 11. Reference case incremental additions and retirements: LNG variant (left) No-LNG variant (right)

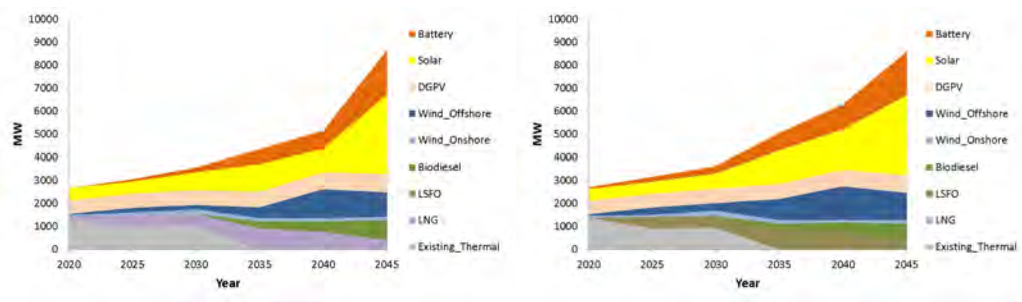


Figure 12. Reference case resource mix by technology type: LNG variant (left) No-LNG variant (right)

Though fuel costs could have a significant impact on the decision to invest in LNG, the total cost of meeting RPS goals is dominated by capital investments. Low variable cost but high fixed cost resources, including batteries, photovoltaics and wind, see the largest procurement over the period of study. Fuel costs will represent a diminishing portion of revenue recovery – the increasing proportion of renewables and storage infrastructure will act as a hedge against global fuel price volatility.

In the Reference LNG case, for example, the incremental annual fixed costs attributed to new resource additions increase to nearly $2billion per year by 2045. Figure 13 shows the progression of the incremental fixed costs over the period of study and Figure 14 shows the corresponding operating cost. Even by 2025, the operating cost becomes relatively small compared with the incremental fixed costs. This is before including fixed costs related to existing infrastructure, supporting LNG infrastructure, and new distribution and transmission infrastructure. As the RPS increases, the importance of fuel costs in resource procurement decisions becomes marginalized. Figure 11 shows LNG being installed in 2035 but beyond that time period, only fuel switching to biodiesel is selected from conventional generation options.

In all cases, the increase in cost over the 5 year period from 2040 to 2045 is significant, approaching an increase in annual fixed cost of ~$800M. This does not include the costs of distribution and transmission infrastructure required to support the transition to 100% RPS.

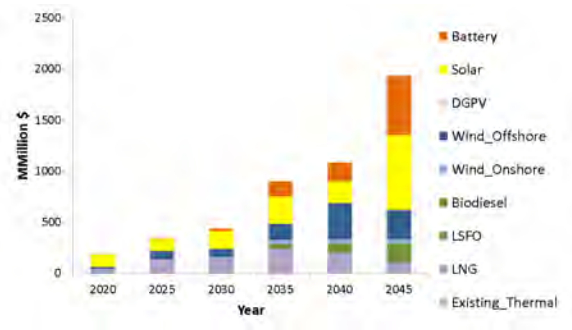


Figure 13. Annual incremental fixed cost from new capacity additions in the Reference LNG case

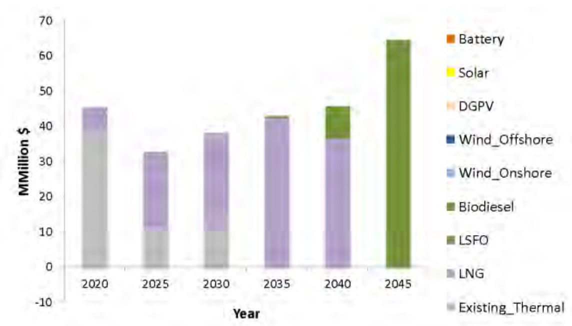


Figure 14. Annual operating cost of the system in the Reference LNG case

5.2 Which policy decisions are the most favorable?

In 2030, the most significant driver of differences in the annualized cost impact of reaching Hawaii's RPS goals is whether LNG is selected or not. Figure 15 shows the operating and incremental fixed costs of each policy scenario relative to the Reference case with Reference fuel assumptions. The range of each bar represents the low to high fuel scenarios.

The Reference No-LNG case is up to ~4 c/kWh of load higher cost in 2030 over the set of HECO fuel price assumptions. The result is similar in the Flexible Loads, Limited Wind, Direct Electrification (EV), and Flexible Electrification cases. These costs do not reflect the indirect costs of LNG such as the storage facilities.

The impact on costs of different policy scenarios are less pronounced in 2030. The effect of these policies is to change least cost procurement strategy over time. In 2030 the impact on procurement is relatively small due to the lower RPS. Flexible loads however show an impact of ~0.1 c/kWh of load savings in the LNG variant. The Direct Electrification case shows a slight increase of up to 0.2 c/kWh. Both the Limited Wind case and the Flex Electrification case change very little on a c/kWh basis relative to the Reference case.

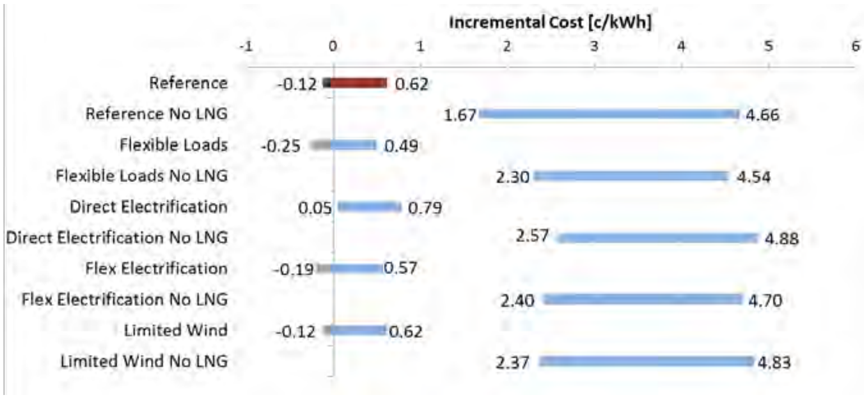


Figure 15. Comparison of operating and incremental fixed costs in 2030

In 2045, the procurement strategy in each of the cases varies quite significantly, yet the cost spread between cases is still relatively close, as seen in Figure 16 . The most favorable strategy is shown to the flexible electrification case. The benefits of this and the Direct Electrification case may be even more pronounced if electric vehicles as a replacement for conventionally fueled vehicles bring cost savings to consumers.

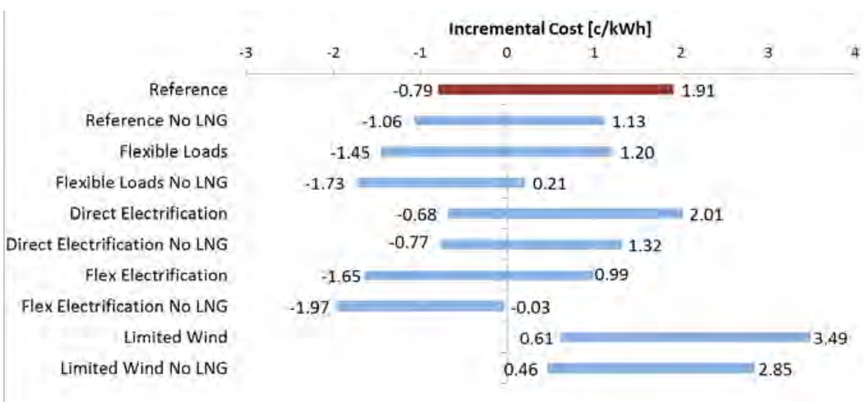


Figure 16. Comparison of operating and incremental fixed costs in 2045

5.3 In each of the policy cases, what are the major investment decisions, and when are they made?

Procurement decisions across the Reference, Flexible Load, Direct Electrification, and Flexible Electrification scenarios remain relatively consistent. Figure 17 through Figure 20 present the procurement and retirement decisions and the total installed capacity for each technology type.

In all cases, the scheduled retirements of ~1000 MW of existing thermal generation happen in 2035 and must be replaced with new resources[16]. The new resources include a combination of new LNG and biofuels and additional renewables alongside battery storage. LNG represents a diminishing but important balancing resource through 2045. The LNG in 2045 shown in the results below is used only to offer contingency reserves, and is assumed to be converted to biofuel.

The flexible load cases reduce the total procurement of batteries, explaining some of the savings of those cases over the Reference. In all cases, the majority of battery procurement happens in 2035 and beyond, with most batteries procured in the final 2045 time period. The significant jump from 70% to 100% RPS in the final time period triggers building over 2000 MW of solar over a 5 year period, requiring storage build of over 1500 MW to utilize the solar produced energy.

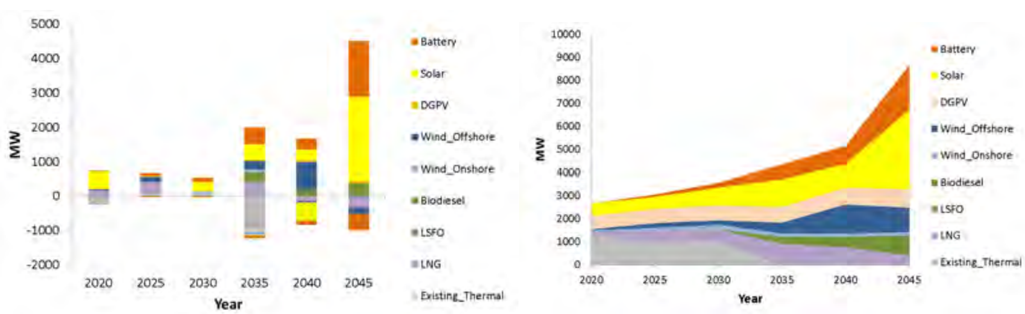
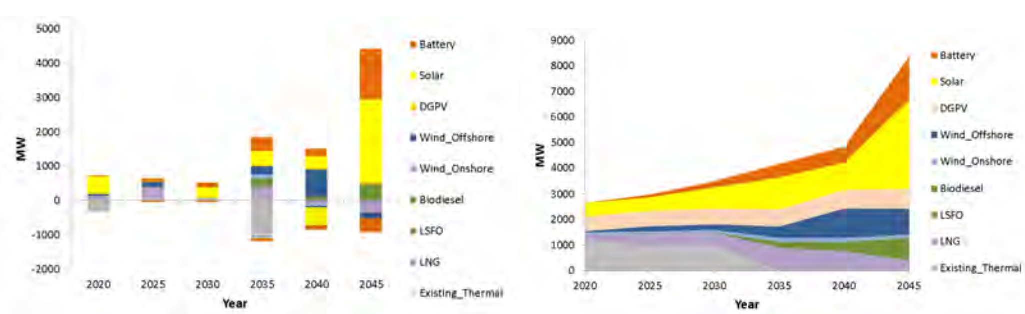


Figure 17. Reference Case LNG: capacity retirements and installations (left), total installed capacity (right)



[16] The Oahu existing resource characteristics, including retirement dates, were taken from data provided by HECO to E3 on November 25th 2015 in support of their efforts to estimate system interconnection limits for uncontrolled DGPV.

Figure 18. Flexible Loads LNG: capacity retirements and installations (left), total installed capacity (right)

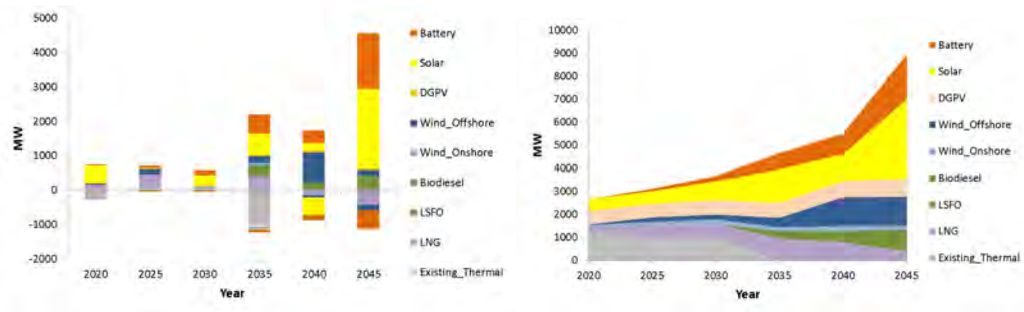


Figure 19. Direct Electrification LNG: capacity retirements and installations (left), total installed capacity (right)

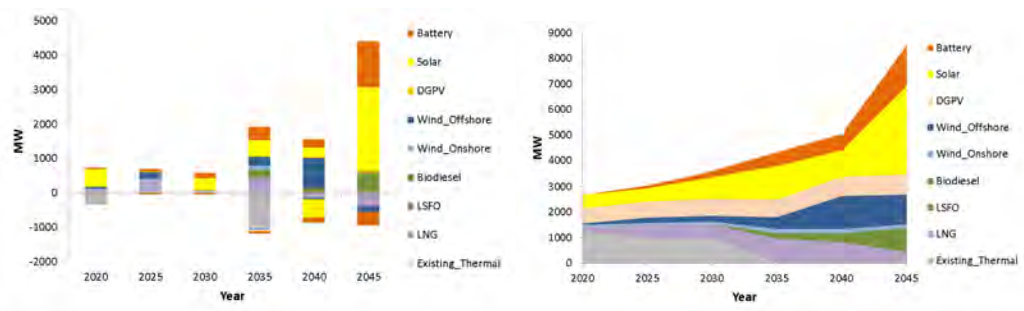


Figure 20. Flex Electrification LNG: capacity retirements and installations (left), total installed capacity (right)

In all cases, the limit to renewables that can be installed on Oahu Island is reached, requiring procurement of off-island generation. Off-island options in RESOLVE include offshore wind generation and imported biofuels. The cases presented above allow unlimited procurement of offshore wind. Total installed wind peaks in 2040, and remains above 1000 MW through 2045. The impact of limiting the offshore wind potential to 400 MW is shown below in Figure 21.

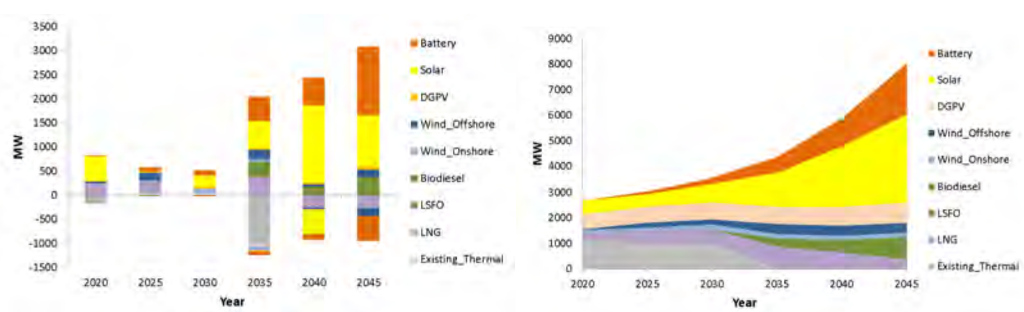


Figure 21. Limited Wind LNG: capacity retirements and installations (left), total installed capacity (right)

The full island potential of utility scale solar is reached in 2045 in the unlimited wind cases. Prior to that, offshore wind is procured, adding capacity in 2025, 2035, and 2040. Limiting offshore wind capacity to 400 MW pushes procurement of utility scale solar and batteries into earlier years.

Limiting the onshore utility scale PV potential to 600 MW triggers a transition to offshore wind with 800 MW installed by 2035 and 2700 MW installed by 2045 compared to 450 MW and 1050 MW in the Reference case, respectively. The number of biofuel MWs is also higher in the limited solar case compared to the Reference, increasing from 860 MW to 1100 MW in 2045, while the number of batteries drops by 500 MW. Batteries are required to shift solar overgeneration energy in the middle of the day in the Reference case. This service is reduced in the low solar case because wind produces energy in all hours rather than just during daylight.

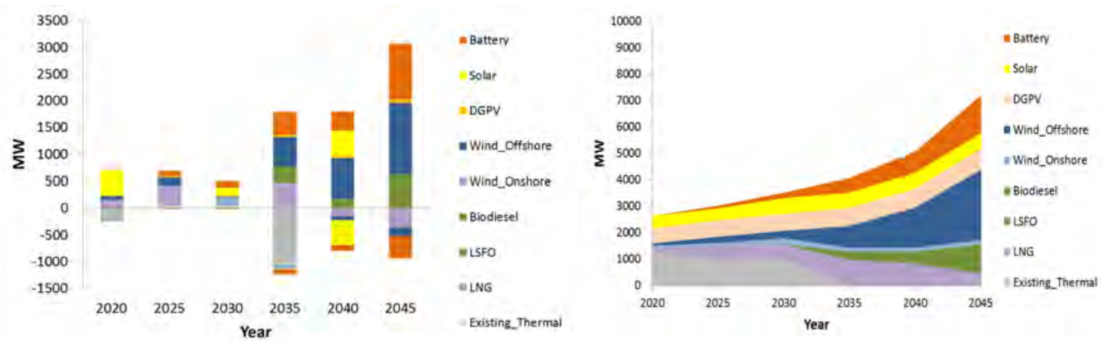


Figure 22. Limited Solar LNG: capacity retirements and installations (left), total installed capacity (right)

The capacity of offshore wind needed to meet RPS requirements in 2045 is large at 2700 MW – a number that has not currently been shown as available to the island. In the case where wind is capped at a lower amount, the remaining RPS requirement would be served by biofuels.

5.4 What is the impact on procurement when the price of storage is varied?

In the low storage case in Figure 23 below, 2150 MW of storage is online in 2045, with 1030 MW of offshore wind and 860 MW of biofuels. This is not significantly different in the Reference case where 1940 MW of storage is online in 2045, with 1060 MW of offshore wind and 860 MW of biofuels. Lower storage prices than in the Reference case are not projected to significantly impact procurement decisions. However, moving to the high storage cost trajectory shown in Figure 25, the amount of storage selected drops to 1020 MW, offshore wind increases to 2490 MW, and 1110 MW of biofuels are online. In addition, total utility scale solar online in 2045 drops from the maximum potential of 3450 MW to 1300 MW. With the projected cost assumptions in the Reference case inputs, procurement decisions in the least cost solution are clearly sensitive to increases in the storage price.

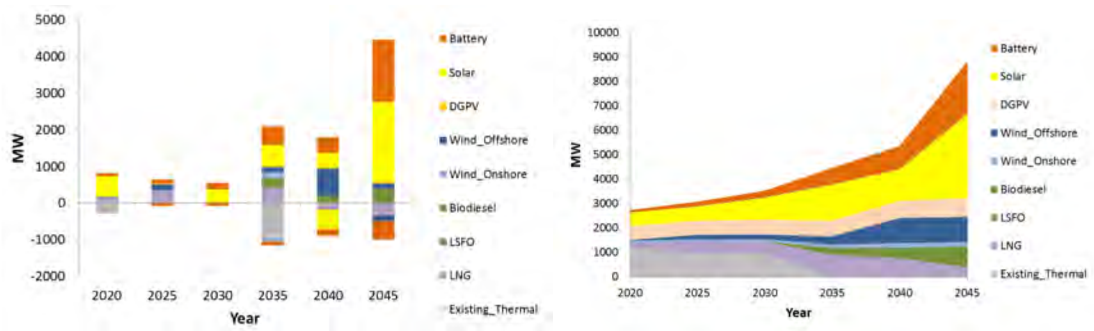


Figure 23. Low storage cost: capacity retirements and installations (left), total installed capacity (right)

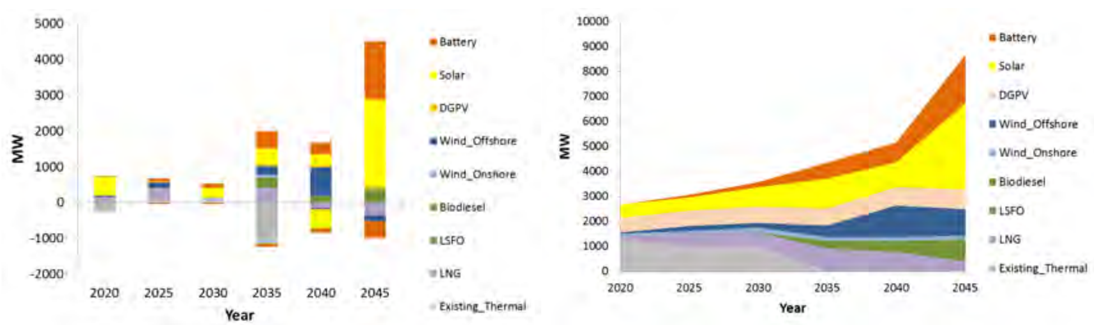


Figure 24. Reference: capacity retirements and installations (left), total installed capacity (right)

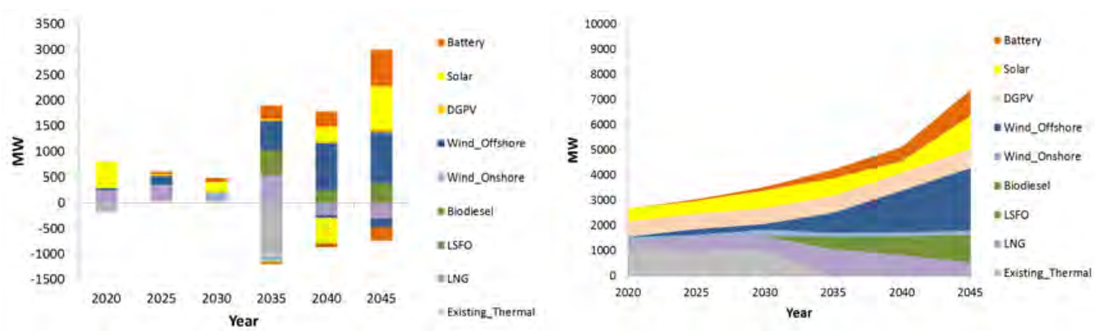


Figure 25. High storage cost: capacity retirements and installations (left), total installed capacity (right)

Higher storage prices can dramatically change the nature of the solution to RPS compliance. Across storage price variants though, the build decisions between now and 2030 remain consistent. Furthermore, storage is a short lead time investment whose optimal deployment is contingent on storage and PV pricing in each year. Investments in longer lead time resources such as LNG that require active policy measures to implement are relatively unaffected by storage pricing. These factors make storage pricing benign as a factor influencing near term planning decisions.

Storage is only one capital investment in a capital dominant portfolio of resources, required to reach 100% RPS by 2045. The decisions made, and the cost of the overall solution will be sensitive to the costs of all of the resources selected, including storage, wind, solar, LNG, and biofuels. Additional work is needed to explore the uncertainties in capital costs and the potential effects those uncertainties have on the decisions going forward.

5.5 How much curtailment is included in least cost operations?

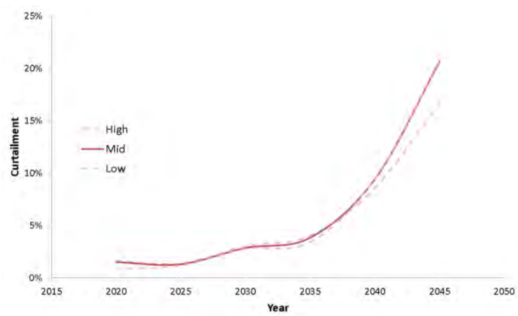
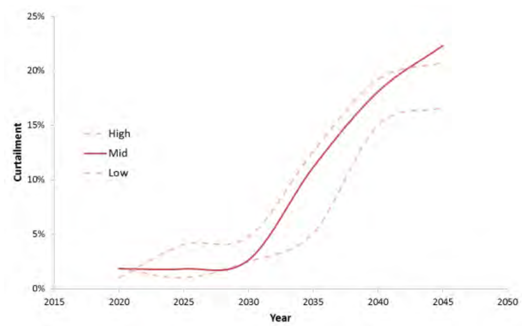
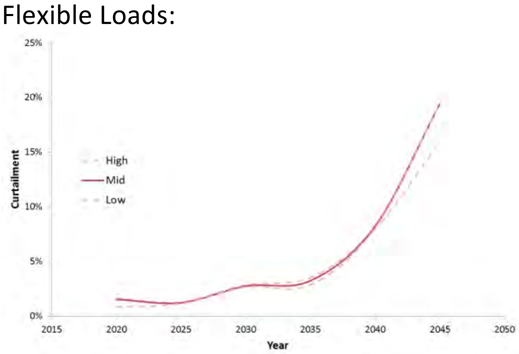
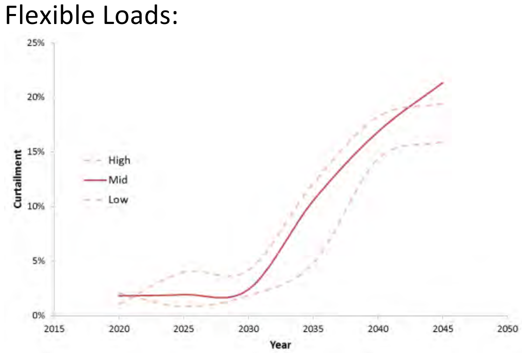
Curtailment of renewables can be a low cost solution to achieving RPS targets. When curtailment first starts happening, only small amounts of energy on particularly problematic days need to be curtailed. An example problematic day could include high solar and wind output coupled with an unusually low midday load that occurs about once a year. If this is the first day of the year where curtailment starts to happen as renewables installations rise, the resulting energy lost only on that day will amount to a very low total energy over the year. As renewable installations rise further however, curtailment will start to happen on other days as well, until curtailment becomes a regular feature in daily dispatch. Higher levels of curtailment start to become more costly as increasing amounts of annual energy are discarded.

In each case run in this analysis, the RESOLVE model makes the least cost tradeoff between curtailing renewables and building other competing integration solutions, for example storage, LNG, and biofuels. The matrix below shows the curtailment levels found for each case. The cost of curtailment is the building of additional renewable capacity to meet the RPS requirements. The tradeoff is therefore the building of some additional renewable capacity against the building of alternative capacity that can prevent curtailment like storage or more flexible generating capacity.

This tradeoff is evident for each of the cases – the low cost fuel scenario has less curtailment because the alternatives become cheaper. This trend however is far less pronounced in the

LNG case than the No-LNG case. Since LNG is more competitive than fuel oil, the levels of curtailment remain lower and fuel cost does not strongly affect the curtailment level.

As with the procurement decisions, the Reference, Flexible Loads, Direct Electrification and Flex Electrification cases all follow a very similar curtailment pattern, though that pattern is significantly different when comparing LNG vs No-LNG. In both the LNG and No-LNG variants, curtailment reaches around 20% of all renewable annual energy by 2045. Curtailment decreases in the final years of the limited offshore wind case, reflecting the limited resources available on the island. In 2045, all solar and wind resources are built, therefore building batteries to utilize more of that generation is in direct competition with biofuels. More batteries are built and the total curtailment falls to 10%.

Case With LNG	Case Without LNG
Reference Case: 	Reference Case: 
Flexible Loads: 	Flexible Loads: 
Direct Electrification:	Direct Electrification:

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

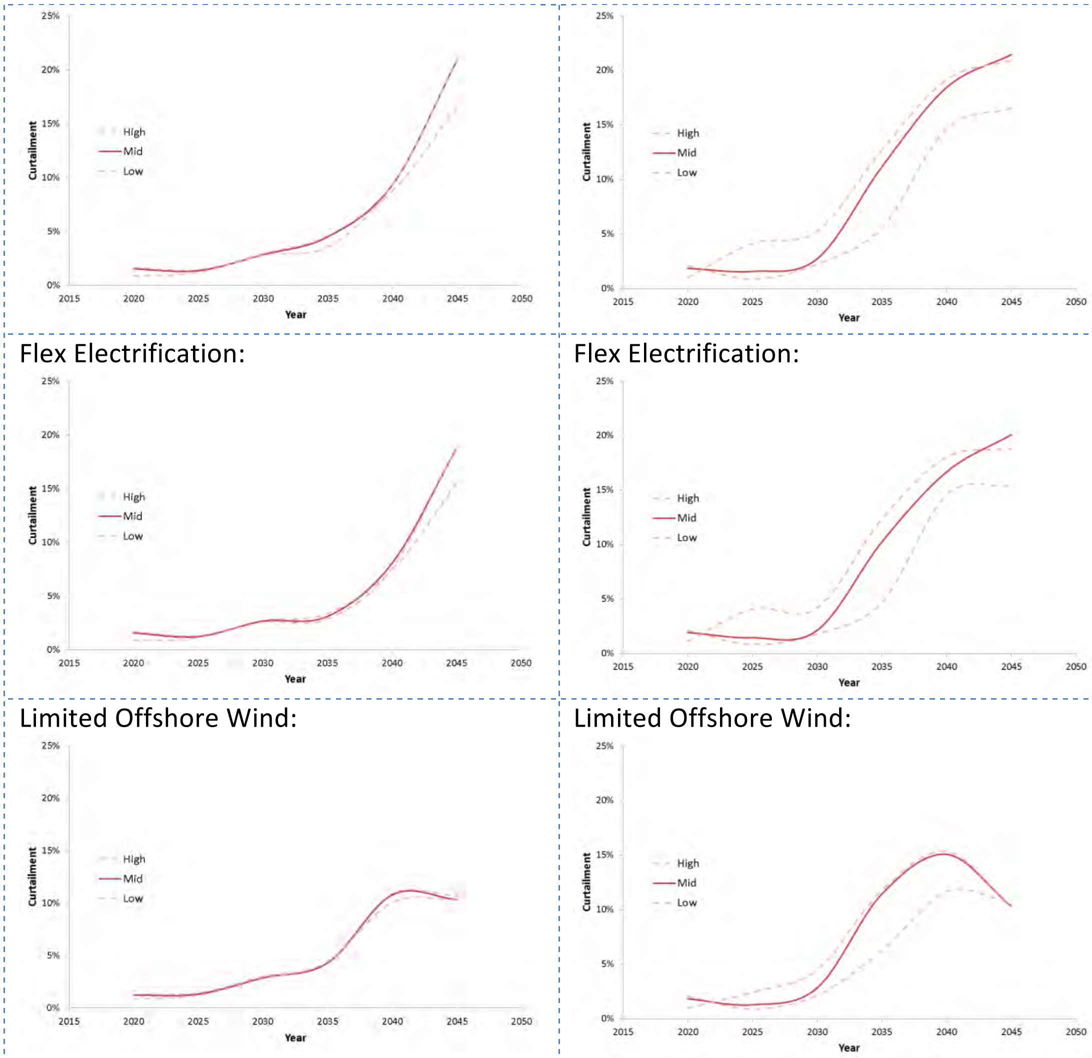


Figure 26. Matrix of renewable curtailment by case

5.6 How does the Produced Fuels case compare to Direct Electrification?

The Produced Fuels case assumes full conversion to synthetic fuel vehicles by 2035, thus adding a large amount of annual electric load to serve the transportation demand. In an already resource-limited system such as Oahu's, this scenario would be a difficult – maybe even infeasible – as it would require additional renewable resources for fuel production. As converting biofuels for hydrogen and synthetic methane fuel production is not a sensible solution due to the cost and inefficiency of such a process, relying on increased the deployment of offshore wind would likely be needed to pursue this pathway. Providing balancing for wind energy, however, poses challenges distinct from those encountered in a solar-dominated system. Unlike solar, which exhibits a diurnal generation pattern, wind does not follow a cyclical pattern. Daily and seasonal variations in wind output can be large. Figure 27 shows the distribution of daily capacity factors based on 2014 offshore wind data: 12% of all days had average capacity factor of less than 10% while 3% of days had average capacity factors of more than 90%.

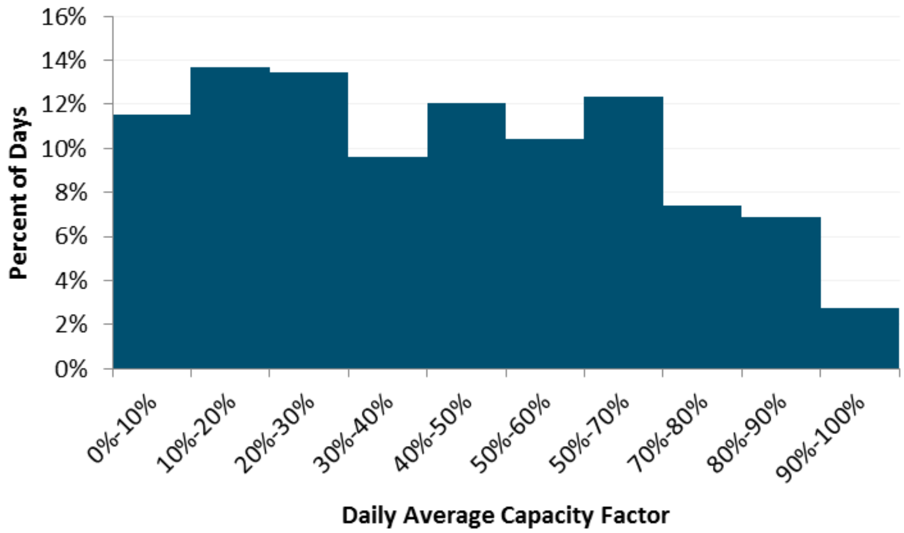


Figure 27. Distribution of daily capacity factors of offshore wind (2014 data).

The balancing requirements of wind are therefore different from those of solar, as wind cannot be balanced on a diurnal basis. Wind patterns can often persist for days or even weeks. In its current formulation, RESOLVE models independent days only, so cannot capture these wind balancing dynamics. Further model development would be required to fully investigate decarbonization pathways heavily dependent on wind deployment.

6 Next Steps

Given the limited amount of time available, the scope of this study was necessarily limited to an initial exploration of the solutions available to Hawaii to integrate 100% renewables. This type of planning framework and system modeling can be used to answer an extensive array of questions about specific planning options or least cost portfolio planning in general. In the study presented above, there are several additional components identified as useful for further study in the PSIP context:

1. The fuel cost spreads in the HECO provided fuel cost scenarios are a major driver of cost effectiveness of LNG. The resulting fuel cost savings of the LNG case are offset by an unknown investment cost in LNG infrastructure. Extended analysis looking at both estimated infrastructure costs and additional forecasted fuel price spreads would improve understanding of the cost effectiveness of the LNG option. In addition, sensitivities on timing of the LNG investment could help understand the potential tradeoffs available between fuel cost savings in the near-term, and increased certainty around fuel price spreads longer term.
2. A key conclusion of the above study is that fuel costs, though important for making decisions about which short term capacity investments to make, are only a small part of the total investments that Hawaii will face when reaching 100% RPS. The majority of expenditure through 2045 is on capital assets including PV, wind, storage, and low capacity factor biofuel capacity. The impacts of how the prices of each of these technologies evolve over time, and how they evolve relative to each other, will have more influence on choices in Hawaii than fuel price sensitivities.
3. Total annual energy curtailment of resources is shown in the above study to give an idea of the tradeoff with investments in other integration solutions. However, to understand the tradeoff between overbuilding renewables and these other solutions, specifically storage in the later years, the cost of the technologies being selected on the margin is important to understand. For example, at total curtailment levels of 10% solar, the marginal curtailment of an additional MW of solar could be 50% or higher. At these levels of marginal curtailment, solar becomes significantly more expensive, and batteries can be more cost effective. Understanding the marginal curtailment and therefore why the least cost decision in a particular year is storage is useful to understand the dynamics of the investment choices, the expected operations required of the system, and inform the types of regulatory and policy choices that may be needed to achieve least cost operations.
4. Policy and regulatory choices in the above study are assumed implicitly in the case definitions. For example, EV incentives may be needed to reach such high electrification in the Direct Electrification case. However, there are many other regulatory and policy changes that would be required to reach the least cost operations modeled in RESOLVE. Examples could include contract structures that

allow for curtailment, efficient dispatch of resources offering curtailment, compensation for low capacity factor generation offering predominantly reserves etc. In further study, these potential barriers to effective implementation could be identified and solutions proposed.

5. In the study above, the technology types considered were necessarily generic. However, within each technology type there are multiple variants that offer a variety of different operating capabilities at different price points. For example, storage technology includes lithium ion, flow batteries, and many other variants that all have different capabilities, price points, and expected price evolution. A more comprehensive study could look at what the merits of each variant look like in context of the other technology solutions available. Furthermore, there are many novel integration solutions proposed with uncertain pricing and benefits. The RESOLVE model and framework can be used to evaluate the near and medium term value of these frontier technologies.
6. The produced fuels case is dependent on high levels of offshore wind development with seasonally varying production. Modeling of the sizing and costing of a system to serve Oahu effectively therefore needs to include a treatment of these wind characteristics. This type of analysis requires further model development.

ASCEND ANALYTICS REPORT

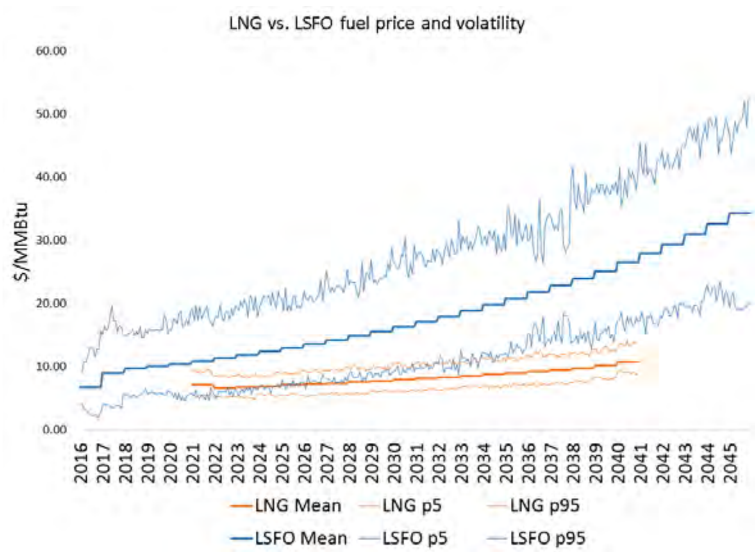
Overview of Current Status and Next Steps

Ascend Analytics' PowerSimm software has been applied to assess the ancillary service requirements and distribution of future production costs. Ascend has applied its PowerSimm stochastic simulation engine to probabilistically envelope future market and weather conditions impacting energy supply. This analysis is being performed on the O'ahu preferred plans (themes 1, 2 and 3). These results will monetize the risk that arises from fuel volatility and variant weather conditions to allow direct comparison between plans that trade risk for capital costs of renewable generation. The stochastic analysis also will be applied to assess the economic merit of renewable generation. This stochastic analysis will be repeated for the Hawaii Island and Maui preferred plans, as well as a pair of custom plans developed by Ascend. In addition, further refinements to the O'ahu plans will be made to ensure that the results are lined up properly with HECO's models. Results will be sent out as simulations are completed and checked.

Ascend has also developed Excel tools for forecasting regulation requirements on the island of Oahu, Maui and Hawaii. This tool allows Hawaiian Electric to understand the flexibility needs of a portfolio with high renewable penetration. Preliminary results and graphics from this tool are presented below.

Valuation of Risk

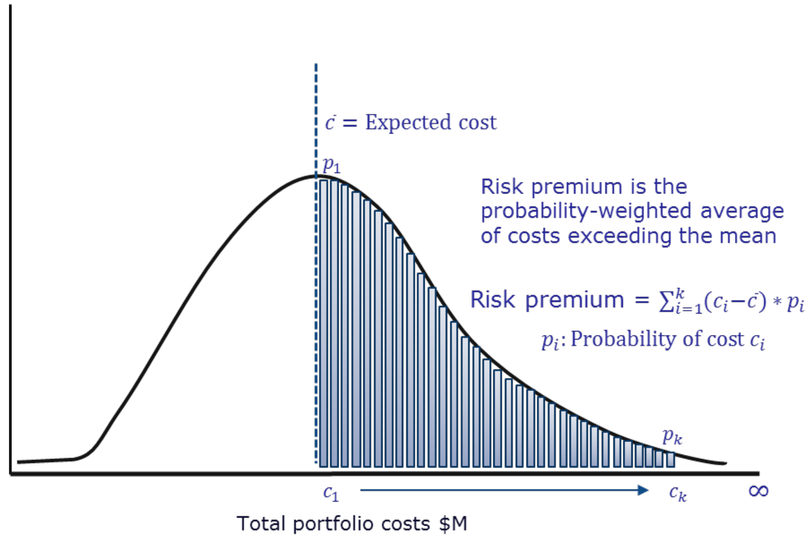
PowerSimm's simulation engine produces realistic simulations of fuel prices, load, renewable generation, and weather. These simulations are subjected to rigorous validation testing to substantiate consistency with underlying causal factor of weather for load and renewables combined with unexplained variability. Market prices for oil, LNG, and bio diesel are simulated based on market expectations of uncertainty through option implied volatilities. The following chart shows the mean, 5th and 95th percentiles of Ascend's simulation results for oil and LNG.



Given the validated simulation engine results for forward/forecast fuel prices, load, renewables, and weather, PowerSimm dispatches HECO's resources each iteration for all years of the study horizon in order to arrive at a distribution of future costs. The expected value of portfolio costs is therefore a robust metric to determine the cost ranking of the different portfolio options, but it does not capture the differences in risk between the portfolios.

PowerSimm monetizes the difference in the shapes of these distribution by use of the risk premium, defined as the integral of the cost distribution above the mean. This is similar to the approach taken by traders to evaluate the value of an option, or by insurance companies in valuing a policy. The derivation of the risk premium is illustrated graphically in the chart below.

Illustration of Risk Premium Concept



The risk premium can be added to the expected value to better approximate the full distribution of costs, and portfolios can be directly compared based on the sum of expected cost plus the risk premium. This risk metric improves upon traditional planning approaches such as cost-at-risk or efficient frontier analysis by providing a single number by which to compare portfolios, rather than requiring a planner to decide on a weighting between cost and risk.

NPV of Portfolio Costs for Themes 1-3

PowerSimm produces a Net Present Value (NPV) of the long-term costs of each plan by calculating future capital expenditures and generation dispatch costs associated with each theme scenario using a 7% discount rate, and includes the unique risk premium for each portfolio.

Assuming the same existing capital infrastructure currently in place for each scenario, we discounted the capital expenditures for each theme, which includes the construction for each new generation unit scheduled to come online in the next 30 years, as well as the costs associated with integrating DGPV units into the system. Generation dispatch costs are calculated using variable and fuel costs which were modeled after the predicted capacity factor for each unit.

Regulation Tool

The Ascend Regulation Tool is an interactive modelling tool that can be used to estimate 1 hour ramps and regulation for a variety of fixed scenarios for day-time and night-time requirements by scaling historical data to correlate with the forecasted load, wind and solar capacities. The regulation tool can query the output of these runs interactively, and allows for the option to choose DGPV forecast scenarios, observed year, and predicted incremental utility solar and wind capacity.

The 1-hour ramp statistic is calculated as the difference between the net-load at a given time and the net-load exactly 1 hour prior to that time. The maximum ramp for each year is reported both for the day-time and night-time. Regulation is calculated as the difference between net-load and load-following, where net load is load – solar – wind, and load following is a linear interpolation of net load through minute 0 of each hour. Regulation is then separated into regulation-up (regulation > 0) and regulation-down (regulation < 0) to remove bias from 0 regulation calculated at minute 0 of each hour. The 95th percentile of regulation-up and the negative of the 5th percentile of regulation-down are then averaged together to form the regulation requirement. These 1 sided confidence bounds combine to form a 95% confidence interval for regulation, without including the zero regulation calculated at minute zero of each hour.

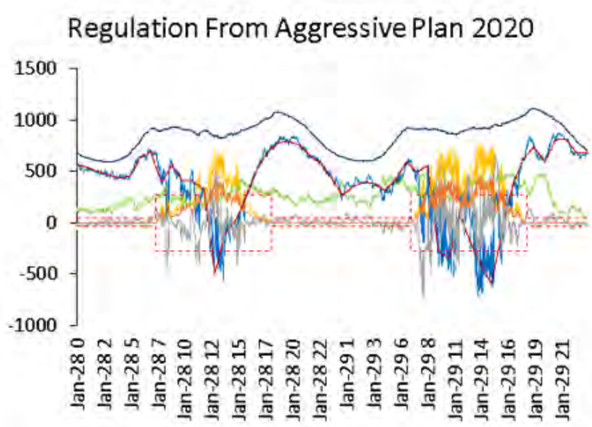
Graphs of regulation and ramps are included below for our internal scenarios as a sample of the key insights gained into load, utility solar, wind, DGPV, net-load, load-following, regulation, and regulation requirements.

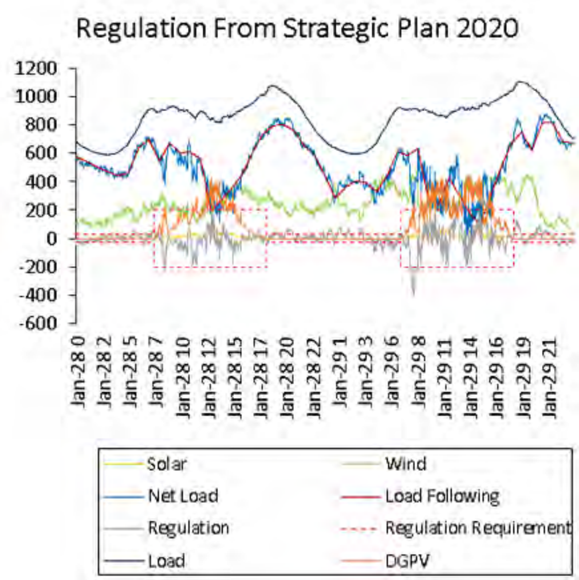
Regulation From Aggressive Plan 2020

Year	2020	
Day-Time Regulation	276	MW
Night-Time Regulation	38	MW
Day-Time Ramp Up	809	MW
Day-Time Ramp Down	(791)	MW
Night-Time Ramp Up	337	MW
Night-Time Ramp Down	(451)	MW

Regulation From Strategic Plan 2020

Year	2020	
Day-Time Regulation	203	MW
Night-Time Regulation	31	MW
Day-Time Ramp Up	611	MW
Day-Time Ramp Down	(582)	MW
Night-Time Ramp Up	265	MW
Night-Time Ramp Down	(395)	MW



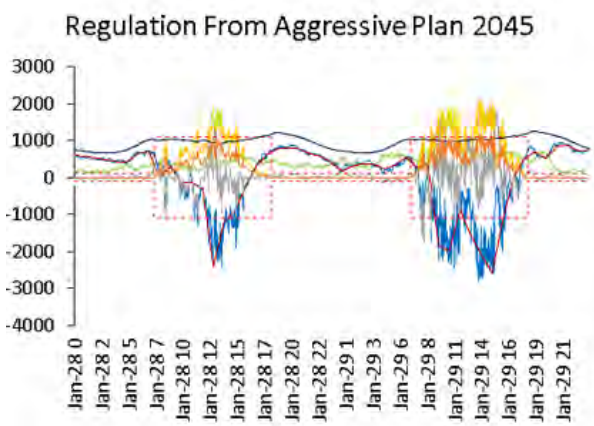


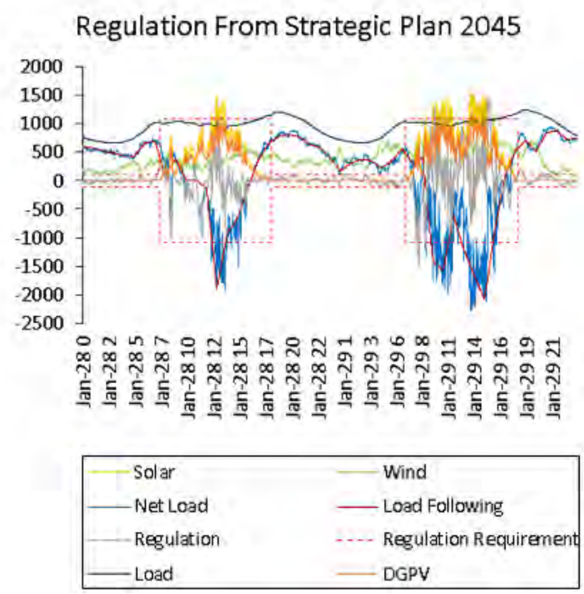
Regulation From Aggressive Plan 2045

Year	2045	
Day-Time Regulation	1,090	MW
Night-Time Regulation	103	MW
Day-Time Ramp Up	3,014	MW
Day-Time Ramp Down	(3,100)	MW
Night-Time Ramp Up	1,145	MW
Night-Time Ramp Down	(926)	MW

Regulation From Strategic Plan 2045

Year	2045	
Day-Time Regulation	1,090	MW
Night-Time Regulation	103	MW
Day-Time Ramp Up	3,014	MW
Day-Time Ramp Down	(3,100)	MW
Night-Time Ramp Up	1,145	MW
Night-Time Ramp Down	(926)	MW

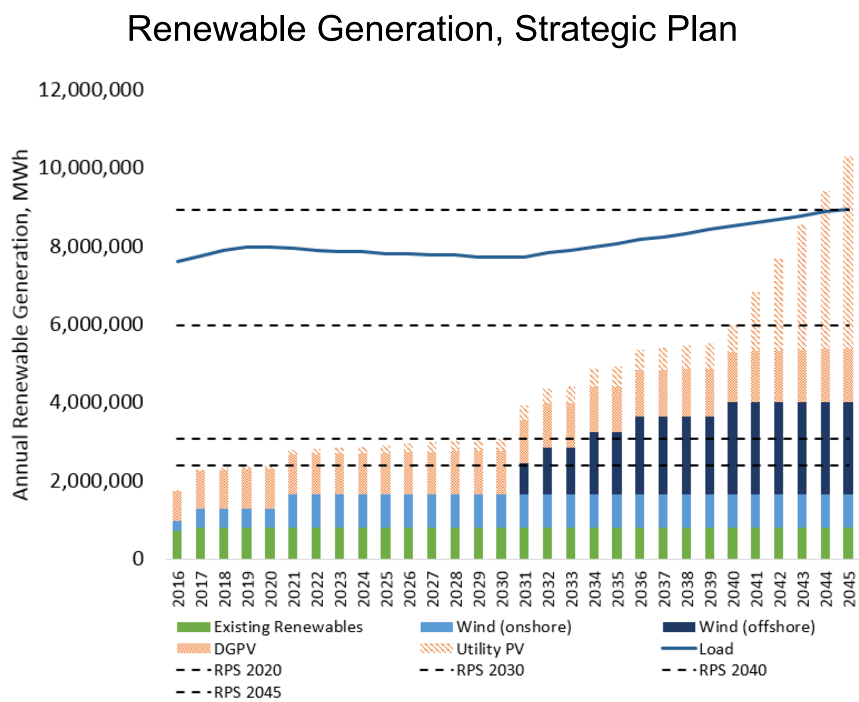


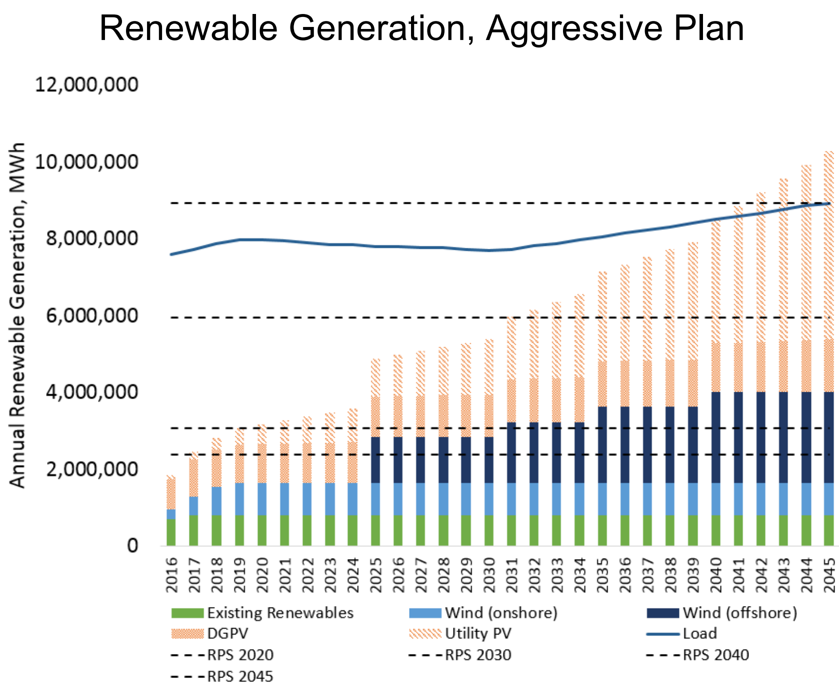


Next Steps - Ascend Expansion Plans

In addition to the preferred plan's put forth by HECO, Ascend created a pair of expansion plans for analysis. These plans were conceived with the objective of reaching the RPS goas purely with wind, solar and battery assets. Two alternate strategies were used to meet these targets, which we have dubbed aggressive and strategic. The strategic plan builds renewables at a deliberate pace, calculated to meet the RPS requirements exactly in each of the target years: 30% renewable energy in 2020, 40% in 2030, 70% in 2040, and 100% in 2045. Since the targets increase the most in the later years, the strategic plan starts slow, and ups the pace later on. The aggressive plan is an inversion of the strategic. It builds rapidly in the early years, vastly exceeding the RPS targets, and slows down in later years, eventually hitting the 100% target in 2045. The early presence of renewables allows this plan to enjoy lower exposure to fuel price risk, but this added security comes at a high cost.

The following charts show the renewable generation levels for the aggressive and strategic plans:





The heavy presence of renewable resources, particularly solar, in both plans results in large amounts of dumped energy during the day when solar generation far exceeds demand. The intermittent nature of renewable generation means that even when concentrated at utility scale, renewables are often unable to reliably serve load. Implementing battery technology as a storage solution can be used to capture over-generation during peak hours and provide energy when wind and solar resources are silent. By building batteries at a rate proportional to the growth of renewables, the aggressive and strategic plans avoid the problem of over and under-production and provide a reliable system. However, because the aggressive plan builds renewables so early, its need for load-shifting comes on much sooner than in the strategic plan. As battery costs are expected to decline significantly over the next 30 years, this leaves the aggressive plan in the disadvantageous position of building batteries soon, before it makes economic sense to do so. Ascend's results will show that what the aggressive plan gains in fuel savings, it loses by building batteries too early.