PG&E'S 2020 DISTRIBUTION GRID NEEDS ASSESSMENT

Together, Building a Better California

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1. Distribution Resources Plan Objectives and Background

On August 14, 2014, the California Public Utilities Commission ("CPUC" or "Commission") instituted Rulemaking ("R.") 14-08-013 to establish policies, procedures, and rules to guide the California investor-owned utilities ("IOU") in developing their Distribution Resources Plan ("DRP") proposals. This rulemaking also established new polices to evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating distributed energy resources ("DER") into the planning and operations of their electric distribution systems.

In July 2015, California IOUs each submitted their respective DRP proposals to the Commission. The Commission organized the review of the DRP filing content into three tracks: Track 1 – Tools and Methodologies, Track 2 – Field Demonstration Projects; and Track 3 – Policy Issues. Various DRP working group meetings and workshops were held to inform the Commission and stakeholders, which ultimately led to several decisions in R.14-08-013.

In February 2018, the Commission issued Decision ("D.") 18-02-004 on Track 3 Policy Issues, sub-track 1 (Growth Scenarios) and sub-track 3 (Distribution Investment and Deferral Process). This decision adopted the Distribution Investment Deferral Framework ("DIDF") and directed the IOUs to file a Grid Needs Assessment ("GNA") by June 1 of each year and a Distribution Deferral Opportunity Report ("DDOR") by September 1 of each year.[1] The GNA, as adopted by D.18-02-004, limits reported "grid needs" to four types of forecasted circuit level system deficiencies, associated with the four distribution services that DERs can provide as adopted in D.16-12-036: capacity, voltage support, reliability (back tie) and resiliency (micro-grid).

In May 2019, the assigned Administrative Law Judge ("ALJ") issued a ruling modifying the DIDF process and updating the date upon which the IOUs submit the GNA and DDOR to August 15 of each year.[2]

In April 2020, the assigned ALJ issued a ruling modifying the DIDF process and filings with respect to the Independent Professional Engineer ("IPE") scope of work. This ruling also updated the 2020-2021 DIDF cycle schedule and defines the DIDF cycle to start on January 1 of each year and concludes July 31 the following year.

In May 2020, the assigned ALJ issued a ruling modifying the DIDF process. This ruling includes process changes to approval for the Integrated Energy Policy Report ("IEPR") dataset used for forecasting, requests for certain datasets to be hosted on the DRP

[1] D.18-02-004, Ordering Paragraph 2.d.
[2] May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, p. 9.

Data Portals, value stacking that may result in deferral projects that exceed the cost cap, changes to how Locational Net Benefit Analysis ("LNBA") data is presented, and recommendations for potential 2021-2022 DIDF cycle reforms.

In June 2020, the assigned ALJ issued a ruling ordering PG&E to launch a DIDF request for offers ("RFO") for the Estrella Substation deferral opportunity to procure DERs to address capacity needs as identified in PG&E's 2020 GNA and DDOR filings.

This report fulfills the requirement associated with the GNA and serves as an annual report that is not subject to Commission approval, as determined by D.18-02-004, "as to not subject the IOUs' funding and investment decisions to additional scrutiny outside of the GRC."[3]

1.1 Objectives of the Distribution Grid Needs Assessment

The objective of the GNA is to provide transparency into the assumptions and results of the distribution planning process that yield the Candidate Deferral Opportunities shortlist, propose grid modernization investments, and proactive hosting capacity upgrades proposed to accommodate forecast DER growth. PG&E's GNA presents data available regarding PG&E's projected distribution grid needs over a five-year planning horizon.[4]

1.2 Regulatory Timelines Associated with the GNA and DIDF

The schedule for stakeholder participation in the Distribution Planning Advisory Group ("DPAG") was specified in the April 2020 ALJ Ruling[5] and is shown below.

Table 1: DPAG Schedule for 2020-2021 DIDF Cycle

Activity*	Date*
Pre-DPAG 2020	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2020**
DPAG 2020	
IOU GNA/DDOR filings, Final IPE Plans circulated	August 15, 2020

[3] D.18-03-023, Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization), p. 18.
[4] Needs for line segments and Volt/Volt-Ampere Reactive (Volt/Var) requirements are only identified for the time horizon for which they are forecast (a three-year period) as specified in ALJ Ruling, p. 6. PG&E applies a 10-year planning horizon for Pre-Application Project needs (although no Pre-Application Projects were identified in PG&E's 2020 DDOR).
[5] April 13, 2020, Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, p. 11-12.

Activity*	Date*
IOUs update DRP Data Portals with GNA/DDOR data	August 30, 2020
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2020
DPAG meetings with each IOU	September 15, 2020 (week of)**
Participants provide questions and comments to IOUs and IPE	September 25, 2020
IOU responses to questions	October 5, 2020
Follow-up IOU meetings via webinar	October 10, 2020 (week of)**
IPE DPAG Reports	October 25, 2020
DIDF Advice Letters submitted	November 15, 2020
Post-DPAG 2020 and 2021	
Provide draft RFO launch materials to Energy Division for approval in consultation with IPE and IE	December 10, 2020
Post-DPAG 2020 and 2021	
Launch RFOs for DERs	January 15, 2021 (or within 30 days of DIDF Advice Letter approval if approval is after December 15, 2020)
Annual DIDF reform comments due	January 20, 2021
IPE Post-DPAG Report	February 5, 2021
Comments on IPE Post-DPAG Report and replies to January 20 reform comments due	February 15, 2021

Notes:
*Activities and dates may be altered by Energy Division based on comments received during Pre-DPAG activities or as needed. Where dates fall on a weekend, the activity is intended to

occur on the following Monday.

**Meeting dates to be assigned by Energy Division during the Pre-DPAG period.

2. PG&E's Distribution Resources Planning Assumptions

The following sections describe the study methodology and assumptions used to forecast and identify distribution grid needs in PG&E's 2020 GNA submittal. These assumptions include distribution planning horizon studied, load forecast assumptions, DER growth forecast assumptions, distribution operational switching/load transfer assumptions, and the technical criteria for identifying grid needs in the GNA.

2.1 Grid Needs Assessment Scope

The scope of this report is as in D.18-02-004, with modifications to the GNA requirements according to the R.14-08-013 May 2019 ALJ Ruling[6] and the May 2020 ALJ Ruling[7]. PG&E's 2020 GNA includes substation/bank, feeder, and line section needs. As adopted in D.18-02-004, grid needs that are reported in this GNA submittal are limited to the forecast deficiencies associated with the four distribution services that DERs can provide as adopted in D.16-12-036, which are distribution capacity, voltage support, reliability (back-tie) and resiliency (micro-grid).

The following definitions for the key distribution services that DERs can provide were adopted by D.16-12-036, *Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot*, issued December 22, 2016:

1. Distribution Capacity services are load-modifying or supply services that DERs provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure;
2. Voltage Support services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems;
3. Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and

[6] May 7, 2019, Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, pp. A1-A2.

[7] May 11, 2020, Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements, Attachment A (subsequently revised on June 12, 2020), pp. 89-98.

4. Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.

Examples of the distribution services that DERs can provide are provided in Appendix 6.2.

2.2 PG&E's Distribution Resources Planning Horizon

To align with the circuit-level planning assumption requirements provided in D.18-02-004 Section 3.4.1.1, PG&E used a five-year forecast as the study horizon for identifying substation and feeder grid needs. For the 2020 GNA submittal, PG&E provides the assessment for the five-year planning horizon for substation and feeders for the years 2020 through 2024. PG&E applies a 10-year planning horizon for Pre-Application Project needs (although no Pre-Application Projects were identified in PG&E's 2020 DDOR). PG&E identifies line section Capacity and Volt/Var needs for a three-year period, and PG&E's 2020 GNA submittal therefore includes needs for line sections for the years 2020 through 2022.[8]

2.3 PG&E's Distribution System Load Forecast Assumptions

PG&E's load growth forecast begins with the most recent approved California Energy Commission ("CEC") PG&E Transmission Access Charge ("TAC") area Peak and Energy Forecast: Mid Baseline Growth Forecast. The CEC 2018 IEPR forecast used for the 2020 GNA can be found here:

https://efiling.energy.ca.gov/GetDocument.aspx?tn=226154&DocumentContentId=56905

Transmission-connected load growth and known new distribution loads are deducted from the CEC system load growth forecast.[9] The resultant growth is distributed out by customer class (residential, industrial, commercial, and agricultural) and is then allocated to PG&E's distribution feeders using geospatial analysis. PG&E uses a 1-in-10-year (90^{th} percentile of high loading) weather event forecast regression curve as the basis for making decisions regarding planned capital upgrades and permanent load transfers.

[8] May 7, 2019, Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, p. 6.
[9] Known new distribution loads are deducted from the systemwide forecast so that they can be added back in as local new load adjustments while maintaining consistency with the CEC forecast in aggregate.

PGE TAC Peak and Energy Forecasts: CEDU 2018 Forecast, Mid Baseline-Mid AAEE/AAPV

Coincident Peak 1 in 2 (MW)			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Peak End Use Consumption (traditional baseline end use load plus electrification and climate change impacts)		21559	21651	22028	22387	22794	23126	23452	23801	24104	24399	24662	24923	25176
2		1 Includes EVs	86	115	144	172	203	238	267	288	311	337	351	373	395
3		1 Includes Other Electrification	7	10	13	16	19	23	26	30	34	36	39	45	49
4		1 Includes Incremental Climate Change Impacts	0	18	37	56	75	95	116	136	158	179	201	224	247
5	Estimated Losses		1792	1767	1765	1764	1771	1777	1786	1798	1807	1815	1820	1824	1826
6	Gross Generation for Peak End Use Consumption (1 plus 5)		23351	23417	23793	24151	24565	24903	25238	25599	25911	26214	26482	26747	27003
7	Self-Generation Corresponding to Peak End Use Consumption (committed)		3130	3499	3922	4316	4662	4946	5199	5435	5659	5881	6107	6340	6584
8		7 Includes Photovoltaic	1944	2291	2658	3022	3339	3594	3819	4029	4226	4422	4623	4831	5050
9		7 Includes Other Private Generation	1159	1163	1165	1167	1169	1170	1171	1171	1170	1170	1170	1170	1170
10		7 includes Storage	26	46	99	127	155	182	209	235	262	288	314	339	365
11	Load-Modifying Demand Response		86	99	80	82	82	83	86	86	87	89	89	89	89
12		11 Includes Non-Event DR	12	24	3	4	4	5	7	7	8	9	9	9	9
13		11 Includes Event-Based DR	74	75	77	78	78	78	79	79	79	80	80	80	80
14	Baseline Net Load Corresponding to Peak End Consumption (6 minus 7 minus 11)*		20135	19819	19791	19753	19821	19874	19954	20079	20165	20245	20286	20318	20329
15	Peak Shift Impact, Baseline Forecast		379	514	651	688	859	1052	1214	1359	1496	1692	1856	2040	2262
16	*Baseline Net System Peak (14 plus 15)*		20514	20333	20442	20441	20681	20926	21168	21438	21661	21937	22142	22358	22591
17	AAEE Savings Corresponding to Peak End Use Consumption (plus losses)		0	175	358	548	744	1021	1275	1524	1760	2041	2229	2443	2657
18	AAPV Generation Corresponding to Peak End Use Consumption (plus avoided losses)		0	0	20	56	93	132	171	211	249	285	321	357	392
19	Managed Net Load Corresponding to Peak End Consumption (14 minus 17 minus 18)*		20135	19644	19413	19150	18984	18721	18507	18344	18156	17918	17736	17518	17281
20	Peak Shift Impact, Managed Forecast		379	516	660	732	962	1298	1587	1879	2115	2509	2872	3043	3352
21	*Managed Net System Peak (19 plus 20)*		20514	20160	20073	19882	19946	20020	20095	20223	20271	20427	20608	20561	20633

* This is the "traditional" (no peak shift) net peak estimate

Figure 1: The CEC PGE TAC Peak Forecasts[10]

2.4 PG&E's Distribution System DER Growth Forecast Assumptions

Separate from load growth, PG&E has incorporated DER adoption into its distribution bank and feeder forecast assumptions. This is accomplished for residential photovoltaics ("PV"), retail non-residential PV, additional achievable PV, energy efficiency for different customer classes, electric vehicles ("EV"), energy storage charge and discharge, and load modifying demand response.[11] The starting point for developing these feeder level DER growth forecasts is the CEC's California Energy Demand ("CED") forecast that is completed at the systemwide level.

Staying consistent with the CED forecast, the systemwide incremental megawatt ("MW") capacity by DER technology type is allocated to the feeders based on allocation methodologies specific to the DER types. Variables used to allocate incremental DER capacity geospatially include consumption by customer class, amount of generation by feeder, historical PV adoption by zip code, the s-curve trending model, observed Distributed Generation ("DG") penetration level, daily peak diversity factors, weather zones, and many other factors specific for each type of DER.[12] Consistent with the Assigned Commissioner's Ruling on the adoption of DERs Growth Scenarios issued August 9, 2017, and the assigned ALJ's Ruling on the Distribution Working Group Progress Report issued August 1, 2018, PG&E's Distribution System DER Growth Assumptions utilize:

- CED Update 2018 Mid Baseline Photovoltaic Generation

[10] CEC 2018 IEPR forecast, https://efiling.energy.ca.gov/GetDocument.aspx?tn=226154&DocumentContentId=56905

[11] Load Modifying Demand Response reshapes or reduces the net load curve as opposed to Supply Resource Demand Response which is integrated into the California Independent System Operator (CAISO) energy markets.

[12] PG&E's DER Growth Forecast Assumptions are subject to updating and revision on an annual basis in accordance with distribution planning criteria and guidance provided by the Commission.

- CED Update 2018 Mid Baseline EVs
- CED Update 2018 Mid Baseline Energy Storage
- CED Update 2018 Mid Baseline LMDR
- CED Update 2018 Mid Baseline-Low Additional Achievable Energy Efficiency

A flowchart of the process used to disaggregate the system-level DER forecasts to feeders can be found in Appendix 6.3. A detailed summary of PG&E's substation bank and feeder DER forecasts that were utilized for this GNA are included in Appendices 6.4 and 6.5.

2.5 Methodology for Substations and Feeders

PG&E uses the LoadSEER Geographical Information System ("GIS") geo-spatial forecasting program, created by Integral Analytics, for modeling substation and feeder demand forecasts and identifying grid needs. This program uses satellite imagery and proprietary data analytics to score each acre in PG&E's territory for the likelihood of increased load by customer class. This GIS model also uses historical land aerial imagery to help determine expansion trends that have occurred within specific areas and takes this information into account for the acre scoring analysis. The spatial forecasting model is enhanced by utilizing an energy consumption model that is weather normalized and includes economic variables. After area scores are determined, the geospatial program then allocates the CEC customer class load growth projections to each parcel and maps the load growth to feeders based on closest proximity. The output of the geo-spatial program is an annual PG&E peak MW growth by feeder, by customer class for the next 10 years. This growth is then uploaded into the LoadSEER Forecast Integration Tool ("LoadSEER FIT") forecasting program.

LoadSEER FIT uses customer-class load shapes to turn the system peak growth amount into a 576-hour[13] load shape that can then be applied to the feeder or bank load shape. LoadSEER FIT creates two forecasts that can be compared: (1) a geospatial forecast derived from CEC system growth; and (2) a regression forecast based on multi-variable analysis and fit with historical recorded loads. LoadSEER FIT's regression methodology performs a multivariable regression to forecast the next 10 years of peak loading on distribution substation banks and feeders. Economic variables and temperature are compared against historic bank and feeder peak loads. With this comparison, the most relevant group of economic variables is selected for each bank and feeder. If there are no variables that have a reasonable fit, a flat, or no growth, regression is applied.

The creation of both geo-spatial load forecasts and regression forecasts provide PG&E's electric distribution planning engineers with two different yet statistically valid

[13] This represents hourly loads for each month for both a typical weekday and weekend day.

forecasts. If the results of both forecasts are similar, they provide PG&E's electric distribution planning engineers with greater confidence in the quality of both forecasts. Otherwise, the electric distribution planning engineers are directed to select the geo-spatial forecast results derived from CEC load forecast. If the geo-spatial forecast is not supported by historic loads and local knowledge, LoadSEER has the capability of creating a forecast that is a blend of geo-spatial and regression forecasts. Whenever a blended forecast is used, justification for the blending must be recorded in LoadSEER and approved by a PG&E senior level distribution planning engineer.

After the 10-year load forecasts are created in LoadSEER FIT, the distribution planning engineers review known new loads which are anticipated based on specific local information. These "new load adjustments" are evaluated to determine if they are covered by existing bank or feeder growth. If the new load adjustments are smaller than the forecast growth for the year that the new service application comes online, then it is assumed the forecast load for that year already embeds the new service application, and the adjustment is disabled. If the new load adjustment exceeds the growth forecast in the year planned but does not exceed the 10-year total growth forecast, then the forecast growth is shifted forward in time to cover the new load adjustment. If a new business load is larger than the forecast 10-year growth, then the load forecast is increased to accommodate the new peak load.

As an additional step to the forecast process, PG&E's electric distribution planning engineers validate and adjust historical peak loads for distribution substation transformer banks and feeders within their local areas to establish a starting point for distribution loading projections.

The following guidelines for verifying and modifying historical loads are typically followed:

- Bank and feeder peak loads are obtained through either the Supervisory Control and Data Acquisition historian system or monthly recorded substation metering data. Peak demand (MW) for banks as well as maximum current loading (amperes) for feeders are recorded along with peak date and time.
- PG&E's electric distribution planning engineers compare recorded peak load information with adjacent days' peak load information to assess whether an unusually high or low load occurred during a planned or unplanned switching condition. Distribution Operations switching log information is reviewed to confirm the timing of the switching operations that create abnormal configurations and the feeders impacted.
- Peak loads on feeders coincident with temporary switched loads are adjusted because loading under temporary switching conditions is not relevant for forecasting normal peak loads and may lead to double counting of loads. If a

peak load is recorded after a newly executed permanent load transfer, then the previous historical loads will be automatically adjusted in LoadSEER to maintain the present feeder configuration when analyzing historic load growth on the feeder.

Historical substation bank and feeder peak loads are adjusted, if necessary, to account for the largest DG facility served by a bank or feeder being offline at peak; also known as N-1 scenario planning. Multiple generators on the same feeder may be grouped into an N-1 scenario if they have a reasonable risk of all being off-line at the same time, such as hydro facilities on the same water source.

A detailed summary of PG&E's substation bank and feeder peak demand forecasts that were utilized for this GNA are included in Appendix 6.5.

2.6 Methodology for Line Sections

PG&E uses the CYME Power Engineering Software for modeling line section demand forecasts and identifying line section needs. The feeder peak demand growth is applied to the corresponding feeder line sections over a three-year period as described in Section 2.2. Only the circuit segments for which the peak needs are identified are listed, rather than all line segments, in PG&E's 2020 GNA.

2.7 Methodology for Voltage Support Needs

Voltage Support needs are identified using CYME Power Engineering Software and three-year forecast as described for capacity planning for line sections (see Section 2.6). As part of the annual distribution planning studies, PG&E forecasts voltage on all energized primary nodes for nearly every feeder for up to three years. PG&E identifies Voltage Support needs based on exceedance of Rule 2 voltage limits under normal operating conditions.[14] To forecast Rule 2 voltage issues, PG&E conducts power flow studies assuming a 1-in-10 year load under normal feeder operating conditions. Since these planning studies are conducted under peak loading conditions, most if not all voltage issues materialize as voltage falling under the 5% nominal voltage Rule 2 band due to excessive voltage drops from the distribution system during high loading conditions or due to incorrect device settings for the forecasted load. Since simulated voltage results are provided for nodes on the distribution primary, an assumed voltage drop on the secondary is needed to define the primary lower limit. Depending on whether a circuit is rural or urban, slightly different secondary voltage drops are assumed.

2.8 Methodology for Reliability (Back-tie) Needs

Reliability (back-tie) services are defined in terms of the emergency capacity deficiency after a bank or feeder loss (i.e., N-1 Scenario). When a forced or a planned outage

[14] PG&E Electric Rule No. 2, https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_2.pdf

occurs, customers will experience a loss of electrical service. If the outage occurs upstream of a sectionalizing device and there is a downstream open circuit tie, then the upstream device is opened, the downstream ties switch is closed, and service is restored to customers on the non-faulted areas of the feeder. An example is provided in Appendix 6.2.

For PG&E's 2019 GNA, reliability (back-tie) grid needs are identified in the form of emergency bank/feeder capacity needs. Typically, an N-1 contingency study is conducted for each bank/feeder where that bank/feeder experiences an outage and the customers it normally serves need to be switched over to adjacent feeders for temporary service restoration. For a bank N-1 contingency scenario, once these customers have been restored by these temporary feeds, it is then assumed that a mobile transformer can be transported, installed in place of the failed bank, and have its capacity used to pick up the previously switched customers within the 24-hour period. These N-1 scenarios are studied under peak loading conditions. Reliability (back-tie) needs are then defined to provide adequate emergency capacity to handle the N-1 load for up to 24 hours.

2.9 PG&E's Load Transfers and Switching Assumptions

PG&E's 2020 GNA load forecast includes the impact of future planned load transfers and switching operations that do not require a capacity project. The planned load transfers and switching operations are used to balance the load between feeders and banks. Typically, planned load transfers and switching operations, which are utility industry common best practices, are the lowest cost alternatives that take advantage of available existing "back-tie" interconnections and capacity on adjacent distribution feeders and banks.

PG&E's 2020 GNA only includes identified grid needs that require a capacity project to either directly mitigate a need or to enable distribution switching and load transfers that mitigate the need.

2.10 Customer Confidentiality

In order to respect and protect customer privacy PG&E follows aggregation and anonymization rules, the primary of which is referred to as the "15/15 rule." When releasing aggregated non-residential customer usage data, the sample population must be more than 15 customers and no single customer should account for more than 15% of usage at any given time. For residential customers, the minimum requirements are at least 100 customers within the sample. Areas that do not meet these requirements will be listed in this report as "Customer Confidential" or "CC."

3. Distribution Planning Regions

The PG&E distribution service area stretches from Eureka in Northern California to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east. It provides service to 5.4 million electric customer accounts over 107,100 circuit miles of electric distribution lines. PG&E divided the distribution service area into four geographically defined Distribution Planning Regions ("DPR") for this GNA. These regions are: (1) Bay Area; (2) Central Coast, (3) Central Valley; and (4) Northern. Each region aggregates a collection of PG&E operating divisions, as indicated in the DPR area descriptions.

4. 2020 GNA Results

The GNA results are summarized below by the four distribution service types: distribution capacity, voltage support, reliability (back-tie) and resiliency. For each of the four service types, the GNA results are further categorized by whether the need is at the substation (bank), feeder, or line section. Complete GNA results are included in Appendix 6.

In total, there are 582 needs included in PG&E's 2020 GNA. Table 2 summarizes the grid needs by DPR and by service type. The majority of grid needs are Distribution Capacity, Voltage Support, and Reliability (Back-Tie) needs. The grid needs are predominately located in the Central Coast and Central Valley DPRs. Table 3 summarizes the grid needs by service type and by facility type (substation (bank), feeder, or line section). Multiple grid needs may be related and can be solved by a single Planned Investment. Table 4 summarizes the grid needs by Anticipated Need Date. 541 grid needs have an Anticipated Need Date within the next three years, and 41 grid needs have an Anticipated Need Date of 2023 or later.

Table 2: Summary of Grid Needs by Distribution Service Type and Distribution Planning Region

Distribution Planning Region	Distribution Service				Total
	Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency (Microgrid)	
Bay Area	79	5	12	0	**96**
Central Coast	135	27	19	0	**181**
Central Valley	162	50	6	1	**219**
Northern	62	18	6	0	**86**
Totals	**438**	**100**	**43**	**1**	**582**

Table 3: Summary of Grid Needs by Distribution Service Type and Facility Type

Facility Type	Distribution Service				Total
	Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency (Microgrid)	
Substation /Bank	109	0	7	1	**117**
Feeder	187	0	25	0	**212**
Distribution Line	142	100	11	0	**253**
Totals	**438**	**100**	**43**	**1**	**582**

Table 4: Summary of Grid Needs by Anticipated Need Date

Anticipated Need Date					Total
2020	2021	2022	2023	2024	
409	92	40	28	13	**582**

4.1 GNA Capacity Needs

Distribution Capacity services are load-modifying or supply services that DERs provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.

In total, there are 438 substation, feeder, and distribution line segment capacity needs. Table 5 summarizes the capacity needs by DPR and by facility type. The needs are predominately located in the Central Coast and Central Valley DPRs. Table 6 summarizes the capacity needs by Anticipated Need Date. 397 capacity needs have an Anticipated Need Date within the next three years, and 41 capacity needs have an Anticipated Need Date of 2023 or later.

Table 5: Summary of Capacity Grid Needs by Facility Type and Distribution Planning Region

Distribution Planning Region	Facility Type			Total
	Substation / Bank	Feeder	Distribution Line	
Bay Area	17	47	15	**79**
Central Coast	41	60	34	**135**
Central Valley	33	60	69	**162**
Northern	18	20	24	**62**
Totals	**109**	**187**	**142**	**438**

Table 6: Summary of Capacity Grid Needs by Anticipated Need Date

Anticipated Need Date					Total
2020	2021	2022	2023	2024	
285	76	36	28	13	**438**

Within the four distribution services, PG&E has identified two Distribution Capacity needs that are DER driven, Blackwell Bank 1 (GNA_2020_4051) and Huron Bank 1 (GNA_2020_3573). These capacity needs are driven by backflow from PV solar generation on the distribution grid. There are two corresponding Planned Investments, Blackwell Bank 1 (DDOR178) and Huron Bank 1 (DDOR036), that are non-DER solutions (i.e., wires solutions) to address the DER-driven needs (see Section 3.3 of PG&E's 2020 DDOR). Planned and taken steps by PG&E to upgrade monitoring and control systems to allow DERs to meet such needs are described in PG&E's Grid Modernization chapter of PG&E's 2020 GRC filing[15] and include the installation of an Advanced Distribution Management System ("ADMS"). However, until the relevant ADMS functions are ready, PG&E is developing and testing various components required to enable monitoring and control of 3rd party DERs including the use of a 3rd party owned DER Gateway architecture for telemetry and control as well as short-term load forecasting for day-ahead dispatches.

4.2 GNA Voltage Support Needs

Voltage Support services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/ reactive power control systems.

In total, there are 100 substation, feeder, and distribution line segment voltage support needs. Table 7 summarizes the voltage support needs by DPR and by facility type. The needs are predominately located in the Central Coast, Central Valley, and Northern DPRs. All the voltage support needs have a Distribution Line Facility Type. Table 8 summarizes the voltage needs by Anticipated Need Date. All of the voltage support needs have an Anticipated Need Date within the next three years, for the reasons specified in Section 2.7.

[15] PG&E's 2020 GRC Application, December 13, 2018

Table 7: Summary of Voltage Support Grid Needs by Facility Type and Distribution Planning Region

Distribution Planning Region	Facility Type			Total
	Substation / Bank	Feeder	Distribution Line	
Bay Area	0	0	5	**5**
Central Coast	0	0	27	**27**
Central Valley	0	0	50	**50**
Northern	0	0	18	**18**
Totals	**0**	**0**	**100**	**100**

Table 8: Summary of Voltage Support Grid Needs by Anticipated Need Date

Anticipated Need Date					Total
2020	2021	2022	2023	2024	
80	16	4	0	0	**100**

4.3 GNA Reliability (Back-Tie) Needs

Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations and to minimize customer impact during planned outages.

The 2020 GNA includes back-tie capacity grid needs for banks, feeders, and line sections. In total, there are 43 substation (bank), feeder, and distribution line segment reliability (back-tie) needs. Table 9 summarizes the reliability (back-tie) needs by DPR and by facility type. The needs are predominately located in the Bay Area and Central Coast DPRs. Table 10 summarizes the reliability (back-tie) needs by Anticipated Need Date. All of the reliability (back-tie) needs have an Anticipated Need Date of 2020.[16]

[16] The Anticipated Need Date may not always be the same as the In-Service Data of an associated Planned Investment.

Table 9: Summary of Resiliency (Back-Tie) Grid Needs by Facility Type and Distribution Planning Region

Distribution Planning Region	Facility Type			Total
	Substation / Bank	Feeder	Distribution Line	
Bay Area	1	9	2	**12**
Central Coast	5	13	1	**19**
Central Valley	0	2	4	**6**
Northern	1	1	4	**6**
Totals	**7**	**25**	**11**	**43**

Table 10: Summary of Reliability (Back-Tie) Grid Needs by Anticipated Need Date

Anticipated Need Date					Total
2020	2021	2022	2023	2024	
43	0	0	0	0	**43**

The reliability issues listed at Cholame and Templeton are not associated with a Planned Investment and will require the use of contingency plans that may include mobile generation and load shedding. PG&E will continue to monitor the reliability issues and determine whether to include them and potential associated Planned Investments in future DIDF cycles.

4.4 GNA Resiliency (Micro-grid) Needs

As adopted in D.18 02-004 and detailed in the Competitive Solicitation Framework Working Group Final Report,[17] Resiliency (micro-grid) services are load-modifying and/or supply services capable of improving local distribution reliability (provided by elements of the microgrid when operating in grid-connected mode) and/or resiliency (benefits received by the customers participating in the microgrid when it is operating in an islanded mode). This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations. This service will also provide power to islanded end use customers when central power is not supplied and reduce duration of outages. These resiliency services can be

[17] Competitive Solicitation Framework Working Group Final Report: https://drpwg.org/wp-content/uploads/2016/07/2016-08-01-CSFWG-Final-Report-Joint-Competitive-Solicitation-Framework-Working-Group.pdf

provided by a single DER resource and/or an aggregated set of DER resources that are able to reduce the net loading on specific distribution infrastructure coincident with the identified operational need in response to a control signal from the utility. In islanded mode it is necessary for a system to match generation to load while maintaining voltage, frequency, power factor and power quality within appropriate limits, and thus requires an isochronous supply resource. This service will likely require the use of utility wires and must be closely coordinated with the utility such that the areas to be re-powered can be adequately isolated via switching from the surrounding circuit.

PG&E's 2020 GNA includes one Resiliency (micro-grid) need. The Lockeford Bank 1 need requires DER Service Requirements with the ability to operate in an islanded mode (i.e., as a micro-grid). Due to load increases in the area, there is no ability to use existing equipment to transfer load during an outage, even if the capacity need was reduced by the DER. Instead, a DER would need to provide islanding capability during a bank outage. Therefore, PG&E has classified the Lockeford Bank 1 need as a resiliency (micro-grid) need in the 2020 DDOR, because the DER solution to defer the associated Candidate Deferral Opportunity (Lockeford Bank 1) would require a micro-grid.

Additionally, as a part of PG&E's Wildfire Mitigation Plan[18],Microgrid Order Instituting Rulemaking (OIR)[19], and in other proceedings, PG&E is pursuing resiliency and reliability improvements to reduce the risk of wildfires and mitigate the customer impacts of Public Safety Power Shutoff ("PSPS") through permanent and temporary microgrid solutions that source DERs. Projects in this category may include substation temporary generation; temporary mid-feeder microgrids; single-customer temporary generation (to power critical facilities as a last resort to protect public safety); microgrids enabled by the Community Microgrid Enablement Program ("CMEP"); permanent distributed generation-enabled microgrid services ("DGEMS") at substations; and permanent, local, decentralized Remote Grids. Fundamentally, the scope of these projects already requires the inclusion of a DER. These projects are included in the Microgrid OIR and PG&E's Wildfire Mitigation Plan.

The Redwood Coast Airport Renewable Energy Microgrid is another example of PG&E's microgrid work. The project is a collaboration between PG&E, the Redwood Coast Energy Authority, Schatz Energy Research Center at Humboldt State University, Humboldt County, and Tesla, Inc., among others. This front-of-the-meter, multi-customer microgrid project featuring solar PV paired with battery energy storage is on

[18] PG&E's Community Wildfire Safety Program website: http://pgeweb.utility.pge.com/topics/CommunityWildfireSafety
[19] R.19-09-009 - Order Instituting Rulemaking Regarding Microgrids

schedule for commissioning and full operation in October 2021. The DERs sourced for this project would be recorded via a CEC grant.

5. Conclusion

This report fulfills the requirement associated with the filing of PG&E's 2020 GNA annual report. An accompanying report, PG&E's 2020 DDOR report, builds upon the grid needs included herein and identifies Candidate Deferral Opportunities.

6. Appendices

Appendix 6.1: Datasets Guide

This section is a guide on using the GNA datasets including how to interpret specific fields and values. The data package for the 2020 GNA includes:

- DER Growth Forecast Data from 2020-2024
- Demand Forecast Data from 2020-2024
- GNA Data from 2020-2024

All data for the 2020 GNA will be posted on the DRP Data Portal by August 31, 2020[20]. Any interested party can access the data through PG&E web maps by using the following link:

https://www.pge.com/en_US/for-our-business-partners/energy-supply/solar-photovoltaic-and-renewable-auction-mechanism-program-map/solar-photovoltaic-and-renewable-auction-mechanism-program-map.page

DER Growth Forecast Data (Appendix 6.4)

This data provides the trajectory DER growth forecast applied for each feeder for the entire PG&E territory and broken out by DER type. The DER growth amount shown is the expected DER contribution at the time the feeder is at peak demand. These forecast values do not include existing DER capacity but do show incremental DER growth starting in 2020 and continuing until 2024.

Interpreting the Fields:

- Distribution Planning Region: the distribution planning region where the feeder is located.
- Division: the distribution planning division where the feeder is located.
- Facility Name: the name of the feeder.
- Facility ID: a unique identifier linked to the Facility Name.
- Additional Achievable Photovoltaic (AAPV): the additional achievable largest coincidental load decrease, in MW, from photovoltaics. Negative values translate into a load decrease.
- Demand Response: demand response that can be dispatched by PG&E, as opposed to that which can be dispatched by the California Independent System

[20] April 13, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, pp. 11

Operator (CAISO), at feeder coincident peak. Negative values translate into load reduction.

- Electric Vehicles: the largest coincidental load increase, in MW, from Electric Vehicle loads. Positive values translate into a load increase.
- Energy Efficiency: the largest coincidental load reduction, in MW, from adopting Energy Efficiency. Negative values translate into load reduction.
- Energy Storage Charge: the largest coincidental load increase, in MW, from Energy Storage Charge loads. Positive values translate into a load increase.
- Energy Storage Discharge: the largest coincidental load decrease, in MW, from Energy Storage Discharge loads. Negative values translate into a load decrease.
- Photovoltaic (PV) Non-Residential: the largest coincidental load decrease, in MW, from non-residential retail photovoltaics. Negative values translate into a load decrease.
- Photovoltaic (PV) Residential: the largest coincidental load decrease, in MW, from residential retail photovoltaics. Negative values translate into a load decrease.

Demand Forecast and Grid Needs Assessment Data (Appendices 6.5-6.7)

Appendices 6.5-6.7 all show the forecasted grid needs for substation banks, feeders, and line sections across PG&E's territory. Appendix 6.5 shows the Demand Forecast data as 1-in-10-year peak loads for substation banks and feeders, over a 5-year planning horizon. This is compared against the normal operating equipment ratings to determine the bank and feeder capacity needs. Appendix 6.6 shows Reliability and Resiliency needs over a 5-year planning horizon. Appendix 6.7 shows line section voltage and capacity needs over a 3-year planning horizon.

Interpreting the Fields:

- GNA Need ID: a unique identifier that links to DDOR ID in PG&E's accompanying DDOR.
- Distribution Planning Region: the distribution planning region where the facility is located.
- Division: the distribution planning division where the facility is located.
- Facility Name: the name of the substation, bank, feeder, or line section.
- Facility ID: a unique identifier linked to the Facility Name.
- Facility Type: the type of facility – substation, bank, feeder, or line section
- Primary Driver: the primary driver of the grid need, if one exists.
- Distribution Service Required: the distribution service for which the grid need can mapped to. This can be in the form of Capacity, Voltage Support, Reliability (Back-tie), and Resiliency (Micro-grid).

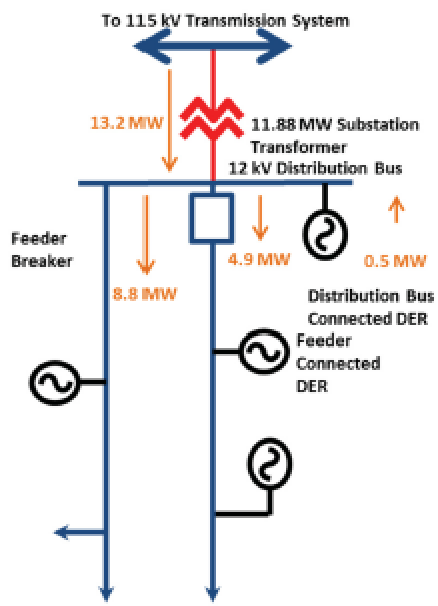
- Anticipated Need Date: the date for which the grid need is estimated to first occur, if there is one.
- Facility Loading (%): Peak Load/Facility Rating x 100, for each year and for the peak (max) year
- Deficiency: Deficiency related to capacity need or other violated criteria related to other grid needs, for each year and for the peak (max) year)
- Deficiency (%): Deficiency/Facility Rating x 100, for each year and for the peak (max) year
- Facility Rating: the normal operating rating of the asset for each year
- Facility Loading: the forecast 1-in-10 year weather net peak loads under normal operating conditions, for each year
- Reliability Rating; The operating rating of the asset under emergency or reliability conditions for each year
- VPU: Voltage per unit for each year
- Volt: The forecasted voltage for each year

Banks, feeders, and line sections with redacted loads and deficiencies are redacted due to their peak loads violating PG&E's adoption of the 15-15 customer privacy rule. A 15-15 violation occurs if the load is comprised of 1 to 15 non-residential customers, if the load is comprised of 1 to 100 residential customers, or if a single customer contributes to more than 15% of the loading value.

Appendix 6.2: Examples of Grid Needs and Associated DER Services

The following examples are based on the Competitive Solicitation Framework Working Group Final Report Filed by the Joint California Investor Own Utilities (August 1, 2016).

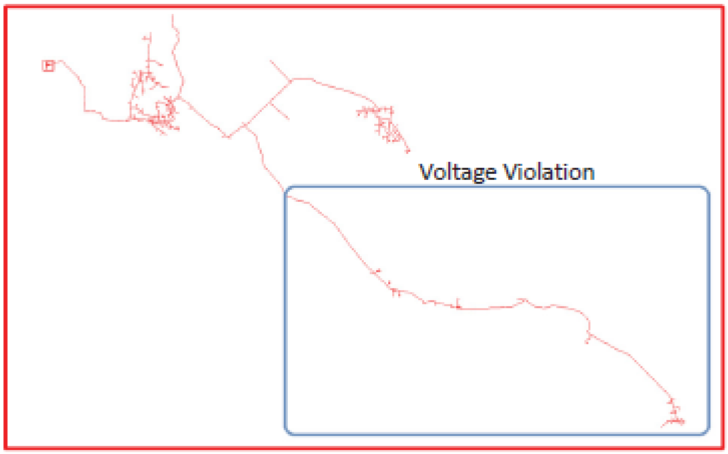
Example A: Distribution Capacity Services
Electric Distribution Planning analysis has identified that a distribution substation transformer is projected to overload in year 2019 during summer peak demand conditions. Specifically, after possible transfers have been completed, this distribution substation transformer is projected to serve a peak demand of 13.2 MW, which exceeds this transformer's thermal capacity rating of 11.88 MW by 11%. Hence, this transformer is projected to overload by 11% under these peak demand conditions. Furthermore, additional Distribution Planning analysis has projected that this overload may reach up to 22% by year 2020 for summer peak demand conditions. The following schematic illustrates this example.



Example of Projected Substation Transformer Overload

To ensure safe and reliable electric service, additional distribution capacity is required for this transformer. This additional capacity can be achieved through a traditional "wires" alternative, which in this case would be the addition of a new substation transformer, or via a DER alternative that effectively reduces this transformer's net loading to be within its thermal rating.

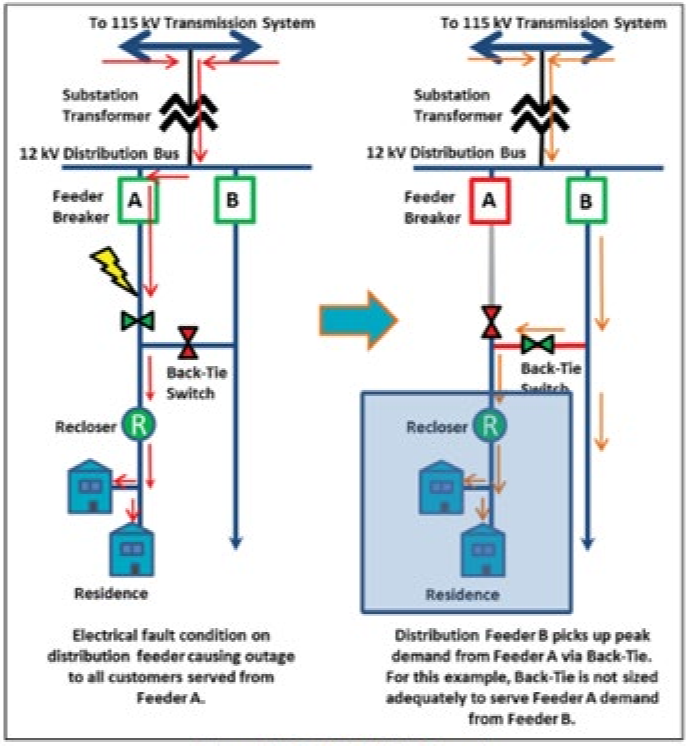
Example B: Voltage Support Service
Electric Distribution Planning utilizes modeling tools to perform power-flow studies of the distribution system simulating electric grid performance. The loading values input for each distribution feeder are based on forecast values. The 2016 results from the power flow identified a feeder with steady-state voltage below the CPUC Rule 2 limit at specific sections on a highly residential feeder. The area in question is also forecast to incur future residential development in the next several years increasing the demand and reducing the voltage further. The following schematic identifies the distribution feeder forecast to have voltage violations during peak conditions.



Example B - Location within Blue square Depicts where DERs are to be located

To ensure safe and reliable electric service as well as maintaining compliance with CPUC Rule 2 voltage limits, additional reactive resources are required. A traditional "wires" solution to provide additional reactive resources is installing a switched capacitor on the feeder or installing a voltage regulator. Another alternative is interconnecting DERs to provide reactive resources effectively acting as a capacitor either when requested by the utility or provided with a required operating profile. The DER reactive resource could be from an individual resource and/or aggregated resources capable of dynamically and demonstrably providing reactive power.

Example C: Reliability Services – Back-Tie
Electric Distribution Planning analysis has identified that a distribution feeder is projected to overload by year 2018 under emergency conditions when providing back-tie capacity support to an adjacent distribution feeder that has an experienced an outage. Specifically, the distribution feeder back-tie is not sized appropriately to transfer peak demand from the de-energized distribution feeder to an adjacent distribution feeder. The following figure illustrates this example.

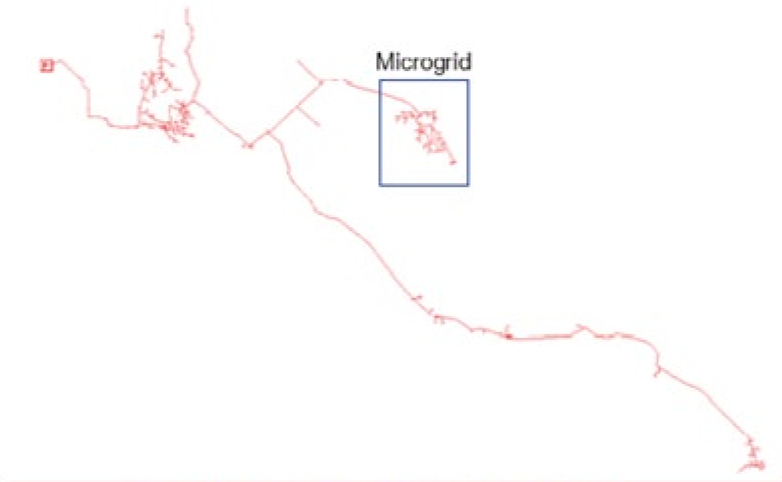


Example C: Back-Tie Capacity

To ensure safe and reliable electric service as well as maintaining compliance with the CPUC Rule 2 voltage limits, additional DER resources may provide additional reliability via incremental back-tie capacity support following distribution feeder outage conditions. A traditional “wires” solution to provide this additional reliability service is to reinforce this back-tie with higher rated infrastructure, which could include larger size electrical line conductors and higher rated back-tie switches. Another alternative is interconnecting and operating DERs to provide resources to restore service to customers either when requested by the utility or provided when a forced outage occurs and incremental back-tie support is needed to serve electric customers from an adjacent feeder. The DER resources could be from an individual resource and/or aggregated resources capable of dynamically and demonstrably providing the electrical services to customers.

Example D: Reliability Services – Resiliency

Electric Distribution Planning utilizes modeling tools to perform power-flow studies of the distribution system simulating electric grid performance. The loading values inputted for each distribution feeder are based on forecast values. Under normal operating scenarios customers are provided electric service that meets Rule 2 levels of service, voltage range of 105% to 95% of nominal 120 V, with frequency typically in the range of 60 +- 0.1 Hz. When a forced or a planned outage occurs, customers will experience a loss of electrical service. If the outage occurs upstream of a sectionalizing device and there is a downstream open circuit tie as discussed in Reliability: Backup Capability, then the upstream device is opened, the downstream ties switch is closed and service is restored to customers on the non-faulted areas of the feeder.



Example of a Distribution Feeder with a Microgrid

Thus, a traditional "wires" solution to provide resiliency for a defined subset of customers is to provide an alternative feed to the customers who would be impacted by an outage. Another alternative is interconnecting DERs to provide resources to restore service to customers either when requested by the utility or provided when a forced outage occurs on the feeder upstream. The DER resources could be from an individual resource and/or aggregated resources capable of dynamically and demonstrably providing the electrical services to customers. The generation resources must be capable of operating in isochronous mode and must have associated controls to match generation to load while maintaining voltage, frequency, and power factor and power quality within appropriate limits.

Appendix 6.3: Flow Chart of DER Forecast

Appendix included as a separate PDF.

Appendix 6.4: GNA Results – DER Growth Forecast

Appendix included as a separate PDF.

Appendix 6.5: GNA Results – Demand Forecast and Bank/Feeder Capacity Needs

Appendix included as a separate PDF.

Appendix 6.6: GNA Results – Reliability/Resiliency Needs

Appendix included as a separate PDF.

Appendix 6.7: GNA Results – Line Section Capacity and Voltage Needs

Appendix included as a separate PDF.