Los Alamos Department of Public Utilities
Los Alamos County

PRELIMINARY IMPLEMENTATION PLAN FOR THE RECOMMENDATIONS IDENTIFIED IN THE FUTURE ELECTRICAL ENERGY RESOURCES REPORT

July 2016

PURPOSE OF THE FEERR IMPLEMENTATION PLAN

At the direction of the Board of Public Utilities (BPU) from the March 16, 2016 board meeting, the Los Alamos Department of Public Utilities' (DPU) has prepared this Preliminary Implementation Plan to provide high level information as to how the DPU proposes to implement the board-adopted recommendations that were identified in the July 7, 2015 Future Electrical Energy Recourses Report (FEERR)*. This FEERR Implementation Plan will discuss the steps to: A) Develop an ***Integrated Resource Plan***, B) Complete ***Studies*** necessary to understand various constraints with DPU's grid, C) Summarize the ***timeline*** and ***decision tree*** for each recommendation and D) Present estimated ***Costs, Resources and Schedules*** necessary to execute this Plan.

Due to the complexity of the various FEERR recommendations, this document is a guide and will continually be reviewed and adjusted by the DPU as more information, conditions, and costs become available. DPU will present the revised plan to the Board each year between May and June.

The FEERR Preliminary Implementation Plan is laid out as follows:

A. ***Integrated Resource Plan***
   Develop an Integrated Resource Plan (IRP) to be the governing document to assist in the decision making process for each FEERR recommendation. It will incorporate data on the various recommendations as they become available. To arrive at a best optimal mix of generation resources that meets DPU's carbon neutral goal at the best cost, the IRP will analyze and prioritize recommendations based on risk, existing generation sources, forecasted loads, transmission and grid considerations, rate impacts, and up and coming changes to the electrical industry.

B. ***Studies***
   Complete various studies that are currently underway to assess potential constraints on the current distribution grid as well as the optimal use of existing infrastructure

*The July 7, 2015 Future Electrical Energy Resources Report was prepared by the Future Energy Resources (FER) Committee, a citizen ad-hoc committee appointed by the Board. The FER was charged to examine and recommend a definition of carbon neutrality for the County; study and recommend future renewable energy generation resources; and study and recommend policy toward distributed generation.

(i.e. battery storage). This information can be added to the IRP and will aid in the decision making process.

C. Timelines/Decision Tree for FEERR Recommendations

Summarize a timeline along with decision tree that needs to occur to provide a road map to implement the board-adopted FEERR recommendation. This Plan covers the anticipated work for the next few years, with multiple step and decisions for the FEERR recommendations with a numerous variables that can change or alter the direction of this plan. The decision made over the next few years will have long term impacts on our rates as we commit to the preferred projects.

D. Cost, Resources and Schedule

A review of costs, resources and schedule that will be necessary to implement just the FEERR Implementation Plan.

A. Integrated Resource Plan

A. Integrated Resource Plan

At the March 2016 board meeting, the Board of Public Utilities directed the DPU to include with the FEERR Implementation Plan, the estimated approximate cost, evaluation of cost-effective alternatives, impacts to customers' bills, and risks for each FEERR recommendation, among other considerations *(March 16, 2016 Utility Board Agenda No. 6.B a.-g)*. DPU proposes that an Integrated Resource Plan (IRP), a separate document from this FEERR Plan, is necessary to accomplish this charge.

An IRP is common in the industry. It is a comprehensive decision tool used to provide reliable, best-cost electricity that incorporates the specific goals of the utility provider to meet forecasted peak and energy demands over a specified future period. The IRP may include some established reserve margin through a combination of supply- and demand-side resources.

LANL and DPU already utilize an IRP developed specifically for the power pool with the goals and objectives spelled out in the Electric Coordination Agreement. However, due to the complex nature of the board-adopted FEERR recommendations specific to the County, as well as the drastically changing electrical industry, ***DPU believes that a new or amended IRP needs to be developed for just DPU. The new IRP will incorporate all the FEERR recommendations and DPU goals to assist the Board and our public tremendously in the decision making process by providing the best available information at the time the decision is to be made.***

That is not to say that the DPU is abandoning the LANL/DPU IRP. DPU is still committed to fulfill its obligation under the current ECA which expires in 2025. DPU and LANL will need to develop a post 2025 power pooling agreement that will benefit and meet the goals of both parties. We recognize that the DPU and LANL goals may or may not be the same. Nevertheless, this post 2025 agreement will also need to be incorporated into the new IRP when appropriate.

The recommendations on power generation assets identified in the FEER Report consist of a range of ideas, including retention of some assets, disposal of others, new acquisition of still others, and integrating distributed energy resources into the mix of generation options. The new IRP will meld these sometimes disparate recommendations into a cohesive and logical path forward.

Steps taken in the creation of an IRP include:

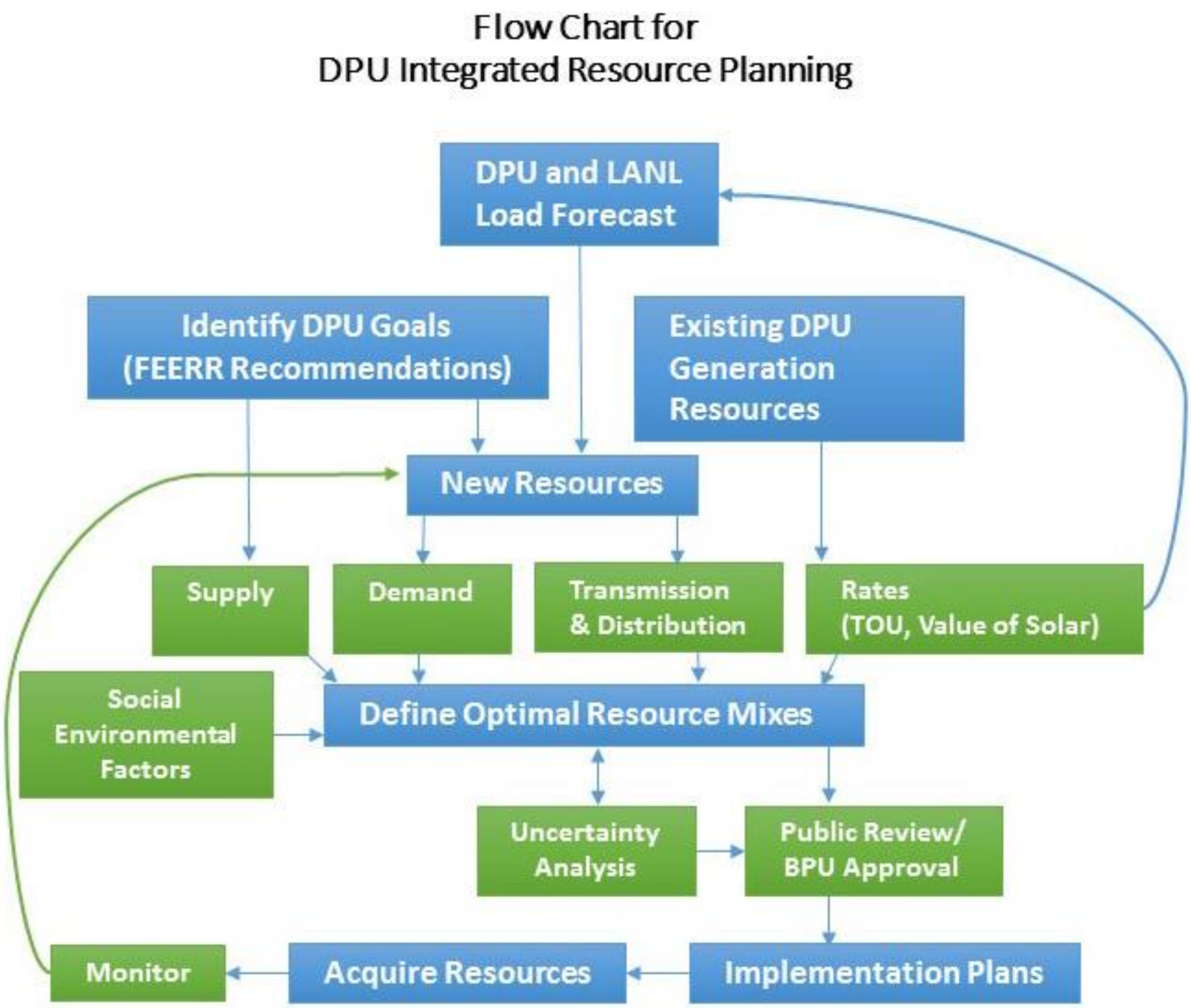
1. Forecasting future loads,
2. Identifying potential resource options to meet future loads
3. Risk analysis
4. Determining the optimal mix of resources based on the goal of minimizing future electrical system cost,
5. Receiving and responding to public participation, and
6. Creating and implementing the resource plan.

Timeline for the new IRP

1. August/September 2016 - Staff will hire a consultant to develop a new IRP
2. December 2016 - A draft IRP will be completed
3. December/January 2017 - Staff will present the draft IRP to the Board of Public Utilities for consideration and input prior to finalizing.

4. March 2017 - After incorporating BPU feedback, staff will ask the Board to officially adopt the Final IRP with a recommended interval for plan updates.

Note: DPU recognizes that some decisions related to the FEERR Recommendations may need to be made by the BPU based on a Draft IRP.



B. Studies

B. *Studies*

DPU has partnered with Los Alamos National Laboratory and Sandia National Laboratories to assess certain conditions and constraints on our distribution grid and determine the best economic use of some of our assets. While these studies were not identified in the FEER Report, DPU determined that they will provide valuable information to be incorporated into the IRP and would assist in the decision making process.

The Studies currently underway are as follows:

Los Alamos National Laboratory, Select Solar, and Positive Energy.
Using grant money from the New Mexico Small Business Administration, LANL, Select Solar and Positive Energy have been looking at the overall distributed energy penetration limits on Los Alamos' distribution grid. The studies also consider bandwidth constraints and penalties coupled with the battery storage available to firm up power.

Timeline

1. 2015 January - Phase 1 of the study began with Select Solar (focus was to determine limits of distributed generation and firming capabilities).
2. 2015 June – Report completed and presented to the FER Committee for consideration in the FEER Report.
3. 2015 July – Phase II of the study began with Positive Energy (focus is to incorporate the bandwidth constraint and penalties associated with falling short or exceeding the 2 MW bandwidth)
4. 2016 August – Report is anticipated to be complete.
5. Inform the BPU of our current constraints, monitor and make plans to accommodate more DER as appropriate. Include transmission and distribution impacts in the IRP as they relate to resource decisions.

Sandia National Laboratories
Grant money from the Department of Energy is being utilized by Sandia National Laboratories and the State of New Mexico Energy Minerals & Natural Resources Department to assess the optimal use of DPU's 8.3 MWh battery storage system for the most economic dispatch of batteries.

Timeline

1. 2015 February - Phase 1 of the study began with the Sandia and the State of New Mexico (focus was to assess the amount of battery storage necessary to make Feeder 16 firm with 100% photovoltaic penetration.).
2. 2016 June – Phase II of the study began with Sandia and the State of New Mexico (focus is to assess the optimal use of the battery storage system for the most

economic dispatch – shave peak loads vs. utilize for spin vs. satisfy bandwidth constraints.

3. 2018 – Report is anticipated to be complete
4. The findings of this study will guide DPU in the most economic dispatch of the battery system and determine whether or not we can accomplish firming while also providing ancillary services such as spinning reserves and/or peak shaving. Currently staff is operating the battery system in the manual mode. Staff does not have the ability to program the Micro EMS to automatically follow the load fluctuations. Investigations are currently underway to replace the Micro EMS with 24/7 support services. With the DER being installed by our public along with the contemplated utility scale projects and/or LANL facility installations, it may require DPU to use the battery system strictly for firming during certain seasons of the year. The cost of firming will be considered in the value of solar calculation as appropriate.

OATI / Trane Distributed Energy Resources Management System (DERMS) Pilot project **-** DPU is currently participating in a pilot project with OATI and Trane, demonstrating the ability to aggregate and control County and LANL HVAC loads from multiple buildings creating a virtual power plant to firm the intermittency of the solar.

C. Timeline/Decision Tree
FEERR Recommendations

C. Timeline/Decision Tree for FEERR Recommendations

The following are the FEERR recommendations adopted by the BPU on January 20, 2016 and March 16, 2016 regularly scheduled Board meetings. Each FEERR recommendation is followed by a brief description of how the work will be accomplished, what are the deliverables, the interdependency between the recommendations and other variables, decision points in the process and an estimated cost and schedule for each.

1. PLAN TO EXIT SAN JUAN GENERATING STATION SHARE OWNERSHIP IN THE MID-2020'S, UNDER THE MOST OPPORTUNE CIRCUMSTANCES. (January 20, 2016 Utility Board Agenda No. 7.B7)

DPU's current contract expires in 2022. A decision as to WHEN to leave (either when contract expires or continue post 2022) must be made in 2018.

Things that need to be considered: LANL load to 2025; price; terms & conditions, LANL acceptance, impact on overall portfolio, public acceptance.

How will be accomplished:

a) 2017 June (approx.) fuel supplier will provide indicative pricing along with terms and conditions for a post 2022 fuel supply.
b) 2017 June (approx.) data from fuel supplier will be incorporated into the IRP to determine impact and best options.
    i. If pricing is too high and terms & conditions do not meet DPU needs, than DPU will make recommendation to let contract expire in 2022 –
        - Need to consider alternate resource to service LANL's load for reminder of ECA contract 2025; and
        - Determine best option for County on what to do with this asset: market interest in purchase of asset from county.
    ii. If pricing, terms and conditions make it a viable resource post 2022:
        - July 2017 Begin discussions with LANL about interest and ECA commitment (2025 or 2028)
        - February/March 2018 DPU to educate public on best information available; Gather public input
        - April 2018 present to BPU and Council public feedback along with staff recommendation.
        - June 2018 Decision made by BPU and Council to either exit in 2022 or exit post 2022 (either 2025 or 2028).
            - ✓ Exit 2022 -
                - need to consider alternate resource to service LANL's load for reminder of ECA contract 2025; and
                - determine best option for County on what to do with this asset: market interest in purchase of asset from county

- ✓ Exit post 2022 –
    - Renegotiate contract with other project owners (work with Board and Council to ensure terms and $$ are appropriate)
    - Inform public of the new terms (when viable – since process will more than likely be confidential)
    - New contract go to Board and Council for approval.

c) 2018 June: Decision finalized by BPU and Council
d) 2018 July: If appropriate, monitor market conditions for most opportune time to buy block power to cover obligations to cover ECA power demands;
e) 2020: If appropriate also consider marketing the asset for sale.
f) Exit Plant (based on decisions made by the BPU and Council in 2018) either 2022, 2025 or 2028.

Deliverables

a) June 2017 - Indicative pricing along with terms and conditions from Fuel Supplier (for post 2022)
b) July 2017 - Evaluation of next best alternative as determined by the IRP with the indicative pricing data known, Power Pool's position - January 2018
c) March 2018 - Public outreach findings
d) April 2018 - Staff recommendation to BPU and Council
e) June 2018 - BPU/Council Decision as to when to exit
f) July 2018 - RFP (if appropriate) for asset's market value

Interdependency

a) No real interdependency on the decision as to when to exit San Juan Generating Station and the other recommendations, specifically other resource recommendations. The reason is because of forecasted load growth requiring additional resources and the difference in the time periods

Estimated Cost:

$50k - $100k for additional support services to assist with the above process

2. CONTINUE TO EXPLORE PARTICIPATION IN THE UAMPS NUCLEAR POWER PROJECT AS A REPLACEMENT SOURCE OF BASE POWER, CARFULLY CONSIDERING PLANT SAFETY, REALISTIC LIFE-CYCLE COSTS, AND POTENTIAL FOR A COOPERATIVE POWER SHARING AGREEMENT WITH DOE/LANL AFTER 2025 (January 20, 2016 Utility Board Agenda No. 7.B9)

Through our membership with the Utah Associated Municipal Power Systems (UAMPS), the County and LANL are currently participating in Phase I of the Carbon Free Power Project (CFPP).

Things that need to be considered: realistic expectation of plant safety, realistic life-cycle costs, potential for a cooperative power sharing agreement with DOE/LANL after 2025, transmission path/costs to get power to load.

How this will be accomplished:

a) Currently UAMPS is completing the siting phase of the CFPP, also known as the fatal flaw analysis.
b) UAMPS staff continues to negotiate with NuScale an Nth-of-kind cost. On a parallel front, UAMPS is working with the congressional delegation on extending the Nuclear Production Tax Credit.
c) September of 2016 (approx.) Participants will have a cost per mega-watt hour for the term of the debt service and a draft of the proposed power purchase agreement.
d) March – December 2016 - DPU staff continues to work with UAMPS on the available transmission capacity to deliver the power from the CFPP to four corners or San Juan transmission hub.
    i. If pricing, terms and conditions make it a possible viable resource post 2025: And pricing and the term for transmission service is acceptable to the County and LANL:
        - September 2016 finalize transmission agreements contingent upon signing of the CFPP power purchase agreement.
        - September 2016 finalize efforts with LANL concerning long term contract to purchase power from the County generated from the CFPP.
        - September 2016 Project financing options presented to UAMPS membership
        - October 2016 NNSA – LANL and LAC vote to proceed with project with 16 MW
        - September - December 2016 DPU Educate public on best information available, Gather public input/Discuss
        - March & April 2017 present to Board and Council public feedback along with Staff recommendation.
    ii. If LANL cannot sign contract for term of debt service or agree with the terms specified by LAC:
        - LAC will notify UAMPS to reduce LAC capacity subscription to 8 MW
        - September 2016 Project financing options presented to UAMPS membership
        - September - December 2016 DPU Educate public on best information available, Gather public input/Discuss
        - March & April 2017 present to Board and Council public feedback along with Staff recommendation.

e) April and May 2017 Decision made by BPU and Council to sign a long term power purchase agreement for the subscribed ownership interest in the CFPP, transmission agreement, If appropriate LANL signs power purchase agreement for term of debt service.

Deliverables

a) September 2016 - Project financing options
b) October 2016 - Public outreach findings
c) March 2017 - Power Purchase Agreement with DOE-LANL
d) April 2017 - Transmission agreement with PAC
e) April 2017 - Power Purchase Agreement with CFPP
f) April/May 2017 - Board/Council Decision on project participation

Interdependency

a) No real interdependency on the decision to participate in the CFPP and the other recommendations, specifically other resource recommendations. The reason is because of forecasted load growth requiring additional resources and the difference in the time periods.

Estimated Cost

$50k Additional support services to assist with the above process

3. PURSUE ACCESS (TRANSFER OR LONG-TERM LEASE) TO SUITABLE UTILITY-SCALE PHOTO-VOLTAIC GENERATION SITES PRESENTLY OWNED BY DOE/LANL. (January 20, 2016 Utility Board Agenda No. 7.B10)

Things that need to be considered:

a) **Cost** - The feasibility of a joint project for a lower cost per kilowatt hour.
b) **Firming** - The intermittency of solar generation still remains a concern of power supply as more and more distributed generation is installed in the community. DPU currently has a two mega-watt limit of customer owned qualifying facilities. This two mega-watts does not include utility scale installations like the installation at the recently closed landfill. Currently there is approximately 1.5 mega-watts of solar generation (customer owned and utility scale) on the system along with 1.8 mega-watts of battery storage.
c) LANL study on the limit for renewable resource capacity in Los Alamos with the current battery storage installed.
d) SNL study on the economic dispatch of the battery capacity here in Los Alamos.
e) Combined PV and Battery Storage project

How this will be accomplished:

a) August of 2015 DOE completed the "DOE Los Alamos National Laboratory – PV Feasibility Assessment. The report summarizes all of the potential sites for solar development, distance to the power grid, within view of public areas and prioritization by LANL on preferred sites. This report is part of the "Los Alamos National Laboratory and Los Alamos County Renewable Generation" study.

   As mentioned above, cost and firming the resource are the two biggest drivers in advancing this effort. Firming the resource is still the most costly but must be considered carefully and compared with Los Alamos next best alternatives. This resource option, economics and rate impacts will be assessed in the completed IRP.

   The IRP is expected to be completed by March of 2017. At this time, staff recommends we address this topic at the LAPP committee meetings with assigned action items. By January 2017 staff issue an RFP for developer interest. Waiting until spring of 2017 when the IRP is completed, more information will be known about LAC participation in the SMR and have better information on a joint solar and battery project cost and feasibility relative to our other alternatives.

b) July 2016 - Determine LAPP interest in participating in joint project with Sandia National Laboratory and Kirtland Airforce base or pursuing a PV project coupled with a firming resource such as a battery or other backup generating resource.
c) July 2016 - Discuss with LAPP option for combined solar and battery project located on preferred LANL site.
d) January 2017 - Solicit terms and conditions from potential developers of PV and Battery project on LANL site with the estimated cost per kWh.

e) March 2017 - Include combined project in IRP and present to Board and Public with recommendation on how to proceed.

Deliverables

a) August 2015 - DOE Los Alamos National Laboratory – PV Feasibility Assessment NREL Final Report
b) March 2017 – Developers interest and estimated cost from project solicitation.

Interdependency

a) This project is dependent on LAC participation in the CFPP with UAMPS and the post 2025 Electric coordination Agreement between LANL and the County.
b) It is also somewhat dependent on recommendation #4 "Evaluate feasibility, including market interest, for a community solar garden…" If the community's preference is to have the solar garden visible in their neighborhood then staff would seek alternative sites such as property owned by the public schools or the County.

Estimated Cost

$0 working with LANL, including solicitations for interested developers will be completed by staff.

4. EVALUATE FEASIBILITY, INCLUDING MARKET INTEREST, FOR A COMMUNITY SOLAR GARDEN IF BANDWIDTH OR OTHER LIMITS ARE NOT BEING APPROACHED BY INDIVIDUAL INSTALLATIONS. (January 20, 2016 Utility Board Agenda No. 7.B13)

Things that need to be considered:

a) The LAPP opportunities on the feasibility of a joint project for a lower cost per kilowatt hour. Will our customers be interested in a share of a joint project?
b) DPU has a current study underway with LANL and SNL to determine how much we can tolerate and the best economic dispatch of the existing battery storage.
c) The LAPP working group has addressed the concerns of DPU promoting a solar garden at the request of our customers. The working group also discussed the potential for LANL sites to install roof top solar with capacities similar to the 50 kilo-watts at the middle school and the 100 kilo-watts at the Smiths Market Place. The working group agreed to monitor the development of solar installations with LAC customers and LANL facilities to ensure one party does not greatly impact the other. The working group also agreed to partner in the project, splitting the generation using the typical split of approximately 80/20 between LANL and LAC.

How this will be accomplished:

a) September 2016 – Survey public on interest in solar garden and location preference.
b) March 2017 – Determine the potential sites for a solar garden based on location preference.

Deliverables

a) December 2016 – Survey results on public interest in solar garden and location preference.
   March 2017 – Potential sites for a solar garden with terms and conditions.

Interdependency

a) It is somewhat dependent on #5, "Develop an engineering model of the distribution system that will indicate how much DER generation can safely be absorbed. (6.A2) Complete studies to determine how much DER generation can be tolerated before causing an unacceptable number of bandwidth exceedances. (6.A3)." Staff doesn't believe the current interest in a solar garden would cause any power quality issues or excessive bandwidth exceedances. This will be better understood after the completion of the survey on public interest.

Estimated Cost

$0 Developing and conducting the survey will most likely be handled by DPU staff.

5. DEVELOP AN ENGINEERING MODEL OF THE DISTRIBUTION SYSTEM THAT WILL INDICATE HOW MUCH DER GENERATION CAN SAFELY BE ABSORBED. (March 16, 2016 Utility Board Agenda No. 6.A2)

COMPLETE STUDIES TO DETERMINE HOW MUCH DER GENERATION CAN BE TOLERATED BEFORE CAUSING AN UNACCEPTABLE NUMBER OF BANDWIDTH EXCEEDANCES. (March 16, 2016 Utility Board Agenda No. 6.A3)

DETERMINE WHETHER UTILITY-SCALE, CIRCUIT, OR NEIGHBORHOOD SCALE DER STORAGE, OR COMBINATION(S) OF THESE APPROACHES MAKE THE MOST SENSE TECHNICALLY AND ECONOMICALLY FOR FIRMING DER GENERATION. (March 16, 2016 Utility Board Agenda No. 6.A7)

These three items are all closely related and need to be considered together, even though implementation will be a multi-step initiative.

Things that need to be considered:

Los Alamos National Laboratory, Select Solar, and Positive Energy Study

Sandia National Laboratories Study

OATI / Trane Distributed Energy Resources Management System (DERMS) Pilot project

UNM Demand Response Study

How will be accomplished:

Phase 1, Develop the engineering analysis with a LAC provided electrical distribution system model and feeder load consisting of connected KVA (transformer capacity) and number of customers. (i.e. Feeder load distribution is uniform with customer consumption based on connected KVA.) **Approximately 9 months of LAC staff support is required; absent that, a contractor must be utilized to perform such work.**

5.1 Upload the 2014 base system model

a. Sept 2016 - Presently, the department has contracted with Milsoft Engineering to convert its 2014 GIS electrical distribution system into a distribution engineering model in Milsoft's Windmill software. Plans are underway to do the site installation and staff training during September 2016.

b. Oct 2016 - Dec 2016 - Once the Windmill model is installed on staff computers, the 2014 electrical model has to be checked for accuracy to reflect the 2016 electrical system configuration. The work required is as follows:

- Add the most recent power line additions, conversions, upgrades, etc.
- The existing electrical model has to be confirmed for overhead vs underground construction; conductor type and size, single phase vs three phase; A, B or C phasing, etc.

- The existing electrical model has to be confirmed for overhead vs underground construction; conductor type and size, single phase vs three phase; A, B or C phasing, etc.
- During this process, new power line additions, deletions, conversions, tie-lines, etc. need to be modeled.
- This process is repeated for every feeder, the each substation; a total of 10 feeders and two substations.
- Note: Up to this point, there is only an electric distribution model with physical power line characteristics/line impedances but no electrical load data. The model consists of line sections (line segments) tied to Nodes (or intersections).

c. Jan 2017 to July 2017 - The next step is to update the electrical model with the transformer size/capacity and number of consumers tied to each unique transformer. The work required is as follows:

   - The transformer size/capacity and number of consumers has to be physically tied to the engineering model's line section on a per-phase basis.
   - This is a tedious process but is a one-time effort.
   - Existing maps, existing GIS information and lots of field work/field review will be required to assign every transformer and customer to the model's corresponding line section

5.2 Procure the services for the engineering analysis

a. Aug 2017 - March 2018; Develop an RFP for the three (3) engineering analysis under this category. It is anticipated the department would provide the following:

   - A 2016 electrical distribution system model. The model would include the connected KVA on a per phase basis, the number of consumers on a per phase basis, per feeder model line section basis.
   - The 2016 monthly substation Feeder KW electrical load profile on an hourly basis. This would be the coincident feeder hourly consumption data.
   - The engineering study would allocate the **measured** substation feeder KW proportionally to the connected KVA along the feeder.

b. The engineering study will develop the following:

   - An engineering model for the electrical distribution system operating as is; i.e. existing system model under present (2016) load conditions on a per feeder basis, per substation basis, and total basis.
   - An engineering model of how much DER each feeder can safely absorb (30%?, 6.A2) without having power quality issues-harmonics, excessive voltage fluctuations, etc. due to sudden loss of DER. (6.A4, item 7).
   - An engineering model of how much DER each substation (Townsite and White Rock) and cumulatively (both substations) the system can absorb without causing excessive 2MW bandwidth exceedances WITH the existing 1.8MW

battery storage system operating and WITHOUT the 1.8MW battery storage system operating. (6.A3)

- Determine how much battery storage would be required at the feeder level, at each substation and system wide, in order to safely add DER and makes the most technically and economically sense for firming DER. (6.A7)

Phase 2, Develop the engineering analysis with a LAC provided electrical distribution system model with actual customer KW/KWH consumption and number of customers. i.e. feeder load distribution is not uniform (as in Phase 1), instead, it's based on actual customer consumption. **Approximately 9 months of LAC staff support is required; absent that, a contractor must be utilized to perform such work.**

5.3 Update the 2016 base system model with actual customer load

a. July 2017-Sept 2018 Wait until the installation of smart meters is underway.

- The smart meter installation project may produce a faster process extract the true customer KWH/KW consumption as described in part c. below.

b. September 2018 - The next step is to correlate the customer meter number with the system transformers. The work required is as follows:

- Presently, the customer meters in the CIS system are NOT tied to a transformer number.
- Each customer meter number has to be physically tied/linked to a system transformer number.
- Existing maps, existing GIS information, and lots of field work/field review will be required to establish the link.
- Again, this is a tedious but one-time effort.

c. December 2018 - The next step is to correlate the customer meter number with the CIS system's customer KWH/KW consumption. The work required is as follows:

- Each customer's electrical load (from the CIS system) has to be tied to a transformer number which is then tied to the electrical model's line section.
- Single phase customer's electrical load needs to be summarized by phase (A or B or C), on a KWH basis, number of customers, and summarized for each transformer, per electrical model line section.
- Three phase customer's electrical load needs to be summarized/distributed on a per phase basis (1/3 on phase A,B,C), number of customers, and summarized for each transformer, per electrical model line section.
- The CIS system would create an ASCII or EXCEL file which summarizes the **tota**l customer load on a per phase basis (A,B,C) for total KWH, total KW, total KVAR, total customers, summarized by transformer number, per electrical model line segment;

- The CIS customer ASCII or EXCEL file can then be uploaded to the Milsoft Engineering Software. The electrical model would have true customer monthly load.
- This file extraction process can be repeated for the monthly winter peak (customer load high), summer months (PV production high), etc.

5.4 Implement Phase 2 engineering analysis

a. March 2019; Update the March 2018 (3) engineering analysis under this category. It is anticipated the department would provide the following:

   - A 2018 electrical distribution system model.
   - A model with customer electrical load that summarizes the total customer load on a per phase basis (A,B,C) for total KWH, total KW, total KVAR, total customers, summarized by transformer number, per electrical model line segment. This would be **non-coincident monthly feeder consumption**.
   - The 2018 monthly substation Feeder KW electrical load profile on an hourly basis. This would be the **coincident feeder** consumption data.

b. The engineering study will develop the following:

   - Update the engineering analysis for the 2018 base model.
   - Repeat the (3) engineering analysis models.
   - It is NOT anticipated the analysis would change much but it's important to perform the analysis with true and correct customer load;

Deliverables

a) September 2016 – Upload Distribution model from MilSoft
b) December 2016 - Develop engineering model with no-load (5.1a, 5.1b)
c) June 2017 - Attach connected load to engineering model (5.1c)
d) March 2018 – Phase 1, Engineering Study (with connected KVA, 5.1c)
e) April 2018 – Provide Phase 1 study results to customers
f) June 2018 - Staff Recommendations to Utilities Board/Council Phase 1
g) July – September 2018 - Smart Meter Implementation/tie smart meters to transformers to MDMS Phase 2
h) December 2018 – Phase 2, Update Engineering Study with true smart meter data;
i) April 2019 - Provide Phase 1 study results to customers; if necessary
j) June 2019 - Staff Recommendations to Utilities Board/Council Phase 2; if necessary

Interdependency

For Phase 2

a) Using Cayenta (potentially): The electrical model will be free standing on its own GIS system (Windmill model) moving forward. However, the customer data is critical to the engineering analysis and resides in the Cayenta CIS system. How we extract the CIS monthly KWH/KW load profile is key but not known at this time; i.e. we have not yet researched this. I would guess it would be a 3 month effort on the part of Cayenta, perhaps $30K cost.

b) Using New ERP: The County is presently updating its ERP software which may likely part ways with Cayenta. Therefore and until we know who the new ERP provider is, we can't attempt to integrate/extract the KWH/KW load data from the new CIS system (this is TBD). County may have ERP contract within the next 3 months? Cost to extract CIS data, TBD.

c) With the Smart meter implementation: The smart meter implementation process may produce a more efficient way to physically connect/tie the meter number with the transformer number during the field installation. Once this process is completed, we may not need to extract the monthly meter KWH/KW from the CIS system; instead, we may be able to extract it directly from the smart meter MDMS (meter data management system). We need to research this further but this may be the best alternative/most efficient way. i.e. the MDMS' purpose is to store meter data where as in the past, the meter data was stored in the CIS system.

Estimated Cost:

a) There is a 3 month effort for 5.1a, 5.1b by staff or others (contract work $30K);
b) There is a 6 month effort for 5.1c, by staff or others (contract work $60K);
c) $100K, estimated costs for the RFP (Phase 1).
d) Cost to support smart meter implementation with in-house staff to link the smart meters to the existing transformers (5.3b); 6 months, $60K;
e) $30K, estimated costs for RFP (Phase 2).
f) Grand Total: $30K + $60K + $100K + $60K +$30K = $280K +/-, contingency, $30K = $310K

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6. **ALL DPU CUSTOMERS (DER AND NON-DER) SHOULD BE CHARGED THE SAME APPROPRIATE RATE(S) FOR ALL SERVICES AND ENERGY (NOT JUST NET ENERGY) SUPPLIED BY THE UTILITY. (March 16, 2016 Utility Board Agenda No. 6.A10)**

   IMPLEMENT TIME-OF-USE PRICING FOR BOTH CONSUMPTION AND GENERATION ONCE SMART METERS ARE AVAILABLE TO DO SO. (March 16, 2016 Utility Board Agenda No. 6.A11)

   DER PRODUCERS SHOULD BE PAID FOR THE POWER THEY SUPPLY TO THE UTILITY BASED ON AT LEAST THE AVERAGE ESTIMATED AVOIDED COST FOR THE TIME PERIOD IN WHICH IT IS SUPPLIED. (March 16, 2016 Utility Board Agenda No. 6.A12)

   Consider whether or not a non-economic Value-or-solar Tariff should be a part of the reimbursement rate structure for DER generation and how it should be phased out as solar benefits relative to other non-carbon sources decline. (March 16, 2016 Utility Board Agenda No. 6.A13)

   COMPLETE SMART METER IMPLEMENTATION FOR ALL CUSTOMERS. (March 16, 2016 Utility Board Agenda No. 6.A1)

These four items are all closely related and need to be considered together, even though implementation will be a multi-step initiative.

Things that need to be considered:

There are other metering/billing concerns besides time of day metering, which will be enabled by AMI meters when implemented. We do not currently measure total DER system output, although as a condition of connection metering to do so is required. Determining total use at the site would be a somewhat convoluted process with existing metering, although it is possible. We could consider requiring different metering, but then implementing becomes an issue, particularly for existing installations. Several of the FER recommendations are affected or limited by the decision to allow customers to opt out of AMI meters or not. This group of recommendations is certainly among them.

Value of different DER may be different, especially considering our current cost split protocol through the ECA. Solar generation contributing to reduction of the system total peak may have benefits for both LANL and LAC, and certainly would have benefits to LAC through reducing LAC's cost allocation. Wind, for example, probably would not have such benefits. Value of DER with storage is probably different then value without, further complicating the discussion.

How this will be accomplished:

a) September 2016 - Complete the currently ongoing "value of DER" study
b) July – December 2016 - Determine a phased approach for implementing different elements
    i. What can we do pre AMI meters

ii. Conversion post AMI Meters
iii. What will we first deploy post AMI meters

c) July – September 2017 - Adopt rates for "pre AMI metering"
   i. September – December 2016 - DER energy – Determine the amount paid for 100% of energy produced via DER and available to serve load
   ii. April 2017 - Utilizing data from 2015 Cost of Service study and 2017 budget, establish rates for pre AMI delivery of power to customers
      - Customer charges – billing, account management
      - Service Charge – for connection to distribution system
      - Energy charge – for 100% of energy consumed by the customer
d) July 2017 - Begin Deploying AMI Metering system wide
   i. Establish/Adopt policy regarding "opt outs"
   ii. Conduct competitive procurement for AMI metering, MDMS, Command Center
   iii. Deploy AMI metering
      - Integration with new ERP
      - Integration with Smart Mobile App, Customer Portal, other systems
e) July – September 2018 - Adopt rates for "post AMI metering"
   i. April 2018 - Conduct study to determine Time Of Use parameters
      - Effect on ECA total costs, cost split
      - Effect on LAC System Peak
      - Demand Response
   ii. Utilizing data from Time of Use study, Prior or updated Cost of Service Study, and relevant budget at the time (this is likely to be a couple of years out, at least), develop rates as in 3(a) and 3(b) above, but also considering relevant time of use parameters.

Deliverables:

a) September 2016 - Value of Solar Tariff w/o time of day considerations $15,000
b) April 2017 – Development of "unbundled" cost of service tariffs for energy consumption
c) April - June 2017 - Public outreach on new Unbundled rate structure and deployment of AMI metering $15,000
d) July - September 2017 - Ordinance for adoption/Implementation of Unbundled rate structure
e) July 2017 - Contract for deployment of AMI metering $75,000
f) April 2018 – Development of New Rate Structure with time of use considerations $250,000
g) May/June 2018 - Public outreach on time of use rate structure $15,000
h) July - September 2018 - Ordinance for adoption/Implementation of time of use rate structure
i) July – September 2018 – Deployment of AMI Metering completed $4.5 million
   i. Integration with new ERP, testing of billing, etc.

Interdependency:

As noted in discussion above

Estimated Cost: $4,870,000

7. ESTABLISH LIMITS, BASED ON DER GENERATION ABSORPTION AND BANDWIDTH EXCEEDANCE CONSIDERATIONS, ON HOW MUCH DER GENERATION CAN BE TOLERATED IN THE SYSTEM. UPDATE THESE LIMITS AS NECESSARY. MAKE IT CLEAR THAT PERMIT ISSUANCE WILL BE SUSPENDED ONCE THOSE LIMITS HAVE BEEN REACHED PENDING EXPANSION OF SYSTEM TOLERANCE OF INCREASED DER GENERATION. (March 16, 2016 Utility Board Agenda No. 6.A4)

REQUIRE SMART INVERTERS (AT LEAST "PHASE 1") ON NEW DER SYSTEMS AS THEY BECOME AVAILABLE. AFTER SMART INVERTERS ARE AVAILABLE, ALL DER SYSTEM INVERTER REPLACEMENTS SHOULD BE OF THE SMART TYPE. (March 16, 2016 Utility Board Agenda No. 6.A5)

MAKE IT CLEAR IN DER INSTALLATION PERMITS THAT RATES AND RATE STRUCTURES ARE NOT GUARANTEED TO ANY POINT IN THE FUTURE. (March 16, 2016 Utility Board Agenda No. 6.A6)

These three items are all closely related and need to be considered together, even though implementation will be a multi-step initiative.

Things that need to be considered:

Los Alamos National Laboratory, Select Solar, and Positive Energy Study

How will be accomplished:

7.1 Update existing Utilities Rules & Regulations after Phase 1 and Phase 2 from Section 5

a) Develop the engineering study on DER Generation absorption as described in Section 5.
   - Establish the DER generation absorption and bandwidth exceedance limits on a per feeder basis, per substation basis, and total basis
b) Modify the Electric Rules and Regulations , Rule E-5
   - Establish the <u>individual</u> DER generation capacity limit; (6.A4)
   - Establish the <u>total</u> DER generation capacity limit; (6.A4)
   - Establish that rate structures are not guaranteed to any point in the future
c) Establish the requirement use of smart inverters when they become available, (6.A5)
   - Modify Rule E-5, E-5.04, to require the use of smart inverters;
   - Modify the Interconnect Agreement between the customer and Utility, to require the use of smart inverters and to make clear that rate structures are not guaranteed to any point in the future (6.A6)
d) Modify the Value of Solar to adequately compensate customers for interconnecting smart inverters willingly

Deliverables

a) September 2016 – Include statement in Rule E-5 and Interconnection Agreement on rates not guaranteed to any point in the future and requirements for the installation and use of smart inverters when available.

b) June 2018 for Phase 1 or March 2019 for Phase 2; Update Rule E-5 and the interconnection agreement to include PV limits by feeder.

Interdependency

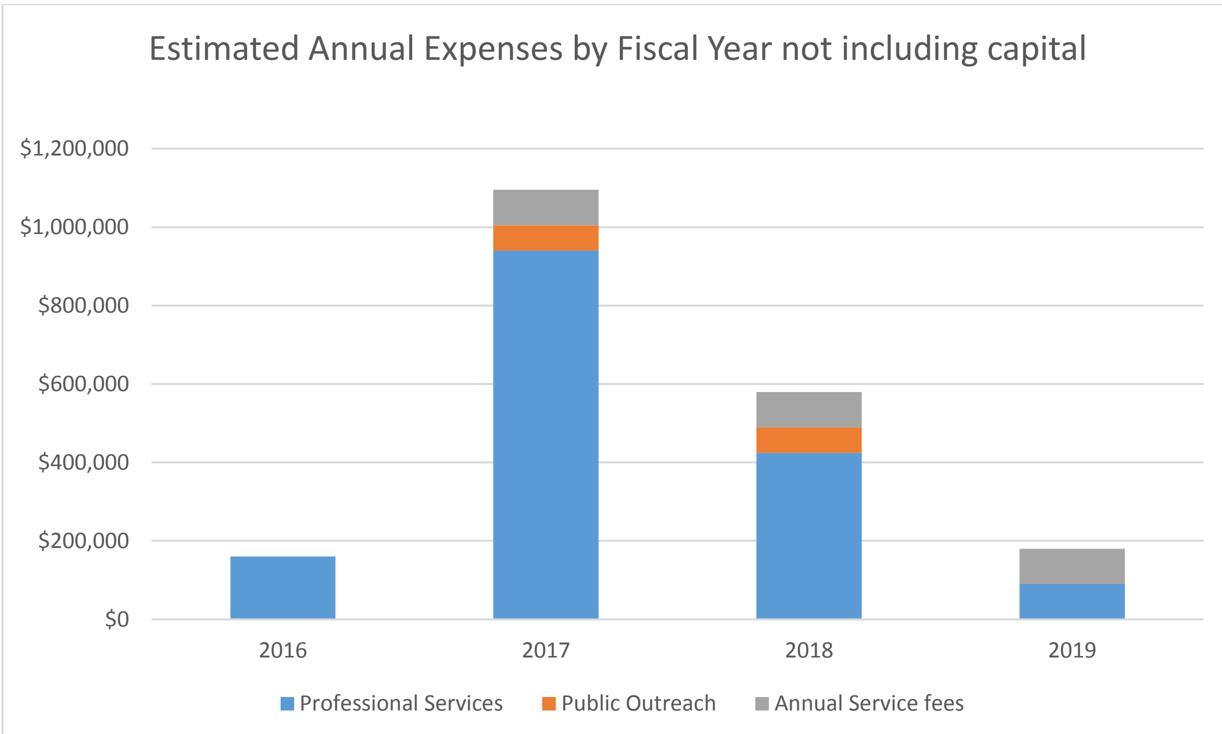
a) Refer to Section 5, interdependency for the DER Generation Study which are still applicable.

Estimated Cost:

a) Cost of the Study are still applicable and are covered under Section 5;
b) Staff time to modify Rule E-5 and present to Utilities Board;
c) Staff time to modify DER Interconnect Agreement and present to Utilities Board;
d) Staff time to modify Value of Solar to incentivize the use of smart inverters

D. Costs, Resources, and Schedule

Costs to Implement the FEERR Plan



Resources

DPU management is assessing how much of the scope for the FEERR Implementation Plan can be realistically completed using in-house staff, adding limited-term staff and/or contracted professional services. As previously stated, this document is a guide and will continually be reviewed and adjusted by the DPU as more information, conditions, and costs become available. DPU will present the revised plan to the Board each year between May and June.

These revisions will be incorporated into DPU's annual strategic planning workshop every year to ensure sufficient resources are considered and budgeted accordingly. This year's strategic plan is scheduled for August 2016.

Preliminary Implementation Plan for FEERR Recomendations

ID	Task Name	2014 2015 2016 2017 2018 2019	
1	**A- Integrated Resource Plan (IRP)**	8/1/16	3/1/17
2	Prepare Outline (Goals and Objectives)	8/1/16	9/1/16
3	Prepare Draft Report	9/2/16	12/1/16
4	Prepare Final Report	12/2/16	3/1/17
5	**B- Studies**	1/2/15	6/1/18
6	LANL- Phase 1	1/2/15	6/1/15
7	LANL- Phase 2	7/1/15	8/1/16
8	SNL- Phase 1	2/2/15	7/1/16
9	SNL- Phase 2	6/2/16	6/1/18
10	**C - FEERR Recommendations (Projects 1 - 8)**	8/1/15	6/2
11	**1- San Juan Generating Station Project**	6/1/17	10/1/18
12	Get pricing and Fuel Supplier Ts&Cs for post 2022	6/1/17	
13	Evaluate IRP's next best alternative	7/3/17	12/1/17
14	Establish Power Pool's position at LAPP meeting	1/1/18	3/17/18
15	Public outreach findings	3/1/18	5/1/18
16	Staff recommendation to Board and Council	4/1/18	
17	Board/Council Decision as to when to exit	4/2/18	5/31/18
18	RFP (if appropriate) for asset's market value	7/2/18	10/1/18
19	**2- Carbon Free Power Project, Small Modular Reactor (UAMPS)**	6/1/16	4/28/17
20	Project financing options	9/1/16	1/1/17
21	Public outreach findings	9/1/16	11/30/16
22	Power Purchase Agreement with DOE/LANL	6/1/16	3/31/17
23	Transmission agreement with PAC	7/1/16	3/31/17
24	Power Purchase Agreement with CFPP	4/28/17	
25	Board/Council Decision on project participation	3/1/17	4/28/17
26	**3- Identify Options for PV Array Property**	8/1/15	2/28/17
27	DOE/LANL's PV Feasibility Assessment NREL Final Report	8/1/15	
28	Developers interest and estimated cost from project solicitation.	1/2/17	2/28/17
29	**4- Determine Community Interest in Solar Garden**	9/1/16	2/28/17
30	Survey results on public interest in solar garden and location preference	9/1/16	11/30/16

Note: While several of these projects will have durations up to 2040 this preliminary schedule only forecasts to 2019. This does not reflect major decisions that will alter the course for these projects past 2019.

Preliminary Implementation Plan for FEERR Recomendations

ID	Task Name	Start	Finish
31	Potential sites for a solar garden with terms and conditions	12/1/16	2/28/17
32	**5- Develop Electric Distribution Models**	9/1/16	6/2
33	Upload Distribution model from MilSoft	9/1/16	10/1/16
34	Develop engineering model with no-load (1a, 1b)	10/3/16	11/30/16
35	Attach connected load to engineering model (1c)7	12/1/16	5/31/17
36	Phase 1, Engineering Study (with connected KVA, 5.1 c)	6/1/17	2/28/18
37	Provide Phase 1 study results to customers	4/2/18	4/30/18
38	Staff recommendation to Utilities Board/Council Phase 1	5/1/18	5/31/18
39	Smart Meter Implementation/tie smart meters to transformers to MDMS Phase 2	9/3/18	10/31/18
40	Phase 2, Update Engineering Study with true smart meter data	12/3/18	3/29/19
41	Provide Phase 2 study results to cistomers; if necessary	4/1/19	4/30/19
42	Staff Recommendations to Utilities Board/Council Phase 2; if necessary	6/3/19	6/28/
43	**6- Development of New Rate Structure**	4/1/16	9/1/18
44	Value of Solar Tariff w/o time of day considerations $15k	4/1/16	8/31/16
45	Development of “unbundled” cost of service tariffs for energy consumption	1/2/17	3/31/17
46	Public outreach on rate structure and AMI metering deployment $15k	4/3/17	5/31/17
47	Ordinance for adoption/Implementation of Unbundled rate structure	7/3/17	8/31/17
48	Contract for deployment of AMI metering $75k	1/2/17	6/30/17
49	Development of New Rate Structure with time of use considerations $250k	4/2/18	9/1/18
50	Public outreach on time of use rate structure $15k	5/1/18	6/29/18
51	Ordinance for adoption/Implementation of time of use rate structure	7/2/18	8/31/18
52	Deployment of AMI Metering completed $4.5M	7/2/18	8/31/18
53	**7- Update Rules and Interconnection Agreement**	7/1/16	2/28/19
54	Modify Rule E-5 and IA (not guaranteed rates/smart inverter rqmts.	7/1/16	8/31/16
55	Phase 1 Update Rule E-5 and IA to include PV limits by feeder	5/1/18	5/31/18
56	Phase 2 Update Rule E-5 and IA to include PV limits by feeder	2/1/19	2/28/19
57	**8- Dispatchable Loads**	10/1/16	2/1/17
58	Results of pilot project with OATI and Trane		10/1/16
59	DPU will present for a phased implementation plans to UB and CC	10/3/16	12/30/16
60	Propose purchase of DERMS	1/2/17	2/1/17

Note: While several of these projects will have durations up to 2040 this preliminary schedule only forecasts to 2019. This does not reflect major decisions that will alter the course for these projects past 2019.