Electrical Storage for Renewable Energy in the KCEC Service Area
Some Preliminary Thoughts by Renewable Taos
July 31, 2015

Preliminary Considerations:

For the foreseeable future, the amount of renewable electricity that can be generated within or for KCEC's service area will be limited by the need to curtail, store or sell excess generation.

Due to the extreme mismatch between KCEC's demand curve and the availability of solar radiation, the potential to produce photovoltaic (PV) electricity that can be used as it is generated is very limited. Preliminary modeling indicates that the limit is an installed capacity of about 50% of peak demand, or 32.5 MW, which would supply about 21% of KCEC's annual demand of 298,500 MWh. A mix of wind and PV may be able to increase these numbers significantly. Based on some wind data from Colorado, the modeling indicates that a combined installed capacity of 56.4 MW (half PV and half wind) could supply 43 % of KCEC's annual demand.

Thus, supplying half or more of KCEC's annual demand from renewable energy would require significant excess renewable capacity. The production from this excess capacity would have to be curtailed, sold or stored. Curtailment means disconnecting (parts of) PV arrays or stopping one or more wind turbines. Small amounts of curtailment are acceptable, but significant amounts raise the cost of electricity because the same capital and O&M costs will produce less electricity. Selling excess generation to other utilities will almost certainly involve losing money. Excess renewable electricity will be even more intermittent than electricity from the same type of facility owned by, or contracted to, another utility, and the other utility would have to pay transmission costs. Therefore, other utilities would only be interested in purchasing KCEC's excess at a significant discount.

Since significant curtailment and selling are not viable options, this leaves storage.

When storing electricity to match supply and demand, the cost of storage is always an additional cost.

For example, with the very optimistic assumptions that PV electricity would cost 0.04 $/kWh, and storage would cost 0.10 $/kWh, stored PV electricity would cost 0.14 $/kWh. This is almost twice the 0.077 $/kWh that KCEC now pays for wholesale electricity. Therefore, storage for the purpose of matching renewable supply with demand is very unlikely to ever be economic, and would violate the Renewable Taos principle that the transition to renewable energy will not raise prices for consumers.

The only economic use of storage that is likely to apply to KCEC is for reducing peak demand charges.

Estimated potential savings from reducing peak demand charges range from $25,000 to $100,000 per month. Storing renewable electricity to reduce peak demands will also allow more renewable energy to be generated and used, without curtailment or sales. If the costs of storage facilities are covered by the peak demand reductions, then there is no additional cost for the stored electricity. The amount of storage that can economically reduce peak demand charges will set the limit for storage of renewable electricity in the KCEC service area.

Reducing peak demand charges, and estimating the potential for doing so economically, are both very difficult.

Reducing peak demand charges is difficult because the peak demand charges that KCEC pays to Tri-State are based on monthly coincident peak demand. Tri-State defines peak periods, and KCEC pays 22.38 $/kW for its highest demand that occurs during a peak period on any day in a monthly billing period. This means that if KCEC successfully reduced its peak demand during 30 days of a 31 day period, but failed to reduce it on one day, then KCEC would save little or no money. (KCEC might save some money if the peak on the one day was lower than the peak on other days would have been, but the monthly peak demand charge would still be based on peak for that day.)

Reducing peak demand charges consistently for every day of a month is difficult because the amount of the peak (kW), and the amount of electricity needed to reduce the peak by a given amount (kWh) are different on every day of the year, and have significant seasonal variations. Thus, deciding when to begin releasing electricity from storage, and at what rate to release it, requires forecasting the height and shape of the peak demand period. The height and shape depend on the sum of all the electricity uses by all of a utility's customers, and these depend on any number of factors, including the weather, the day of the week, and popular sporting events or other entertainment on TV.

While successfully reducing peak demand charges requires forecasting peak demand patterns a few hours in advance, estimating the potential for reducing peak demand requires an ability to predict how successful the daily forecasts will be. In order to determine the optimum energy and power capacities of the storage facilities, it is necessary to predict how much facilities of given capacities will reduce the demand charges for each month of future years, and thus, how much money the facilities will save. This is not an easy task, and will always involve significant amounts of uncertainty and risk.

The cost of storing electricity is difficult to determine.

Estimated costs of electricity from storage vary widely between sources, and the range within any particular source can be significant. It is not always clear whether stated costs include required auxiliary equipment (inverters, transformers, controls), or just the storage medium (batteries, or molten salt tanks). Costs can be stated in terms of the capacity of a storage facility, which can be stated as the maximum amount of energy it can discharge on each cycle ($/kWh), and the maximum amount of power it can discharge ($/kW). Costs can also be stated as the cost for each unit of energy extracted from the facility during its lifetime ($/kWh). The last is often stated as the Levelized Cost of Energy (LCOE). A lot of research is needed to get good estimates of the cost of storage best suited to reducing KCEC's peak demand charges, including future costs in a field where costs are dropping fast. For the purpose of the very preliminary cost estimates in this report, the average LCOE given by Lazard is used: 0.29 $/kWh.

KCEC's Peak Demands & PV Generation:

Tri-State's Peak Periods and Charges:

Tri-State Generation and Transmission Association, Inc. (Tri-State) defines peak periods for summer and winter. The summer peak period is from 7:00 am through 10:00 pm during the months of April through September. The winter peak periods are from 5:30 am through 12:00 pm (noon), and from 4:30 pm through 10:30 pm during the months of October through March. Tri-State charges KCEC 22.38 $/kW for the KCEC's highest demand that occurs in any half-hour period during a peak period throughout a monthly billing cycle. In 2014, KCEC paid Tri-State almost thirteen million dollars ($12,891,000) in demand charges.

Demand Patterns for 2014:

KCEC gave Renewable Taos four years of 15-minute data on total demand and on output from the large PV arrays in the KCEC service area. The demand for 2014 is shown in **Figure 1**. Unlike many other US utilities, which have their peak demands on summer afternoons, KCEC is strongly winter and evening peaking, with the annual peak occurring after sunset in late December or early January. (The 2014 peak of 64.943 MW was at 19:00 on 30 December.) Renewable Taos has created a spreadsheet that allows a user to graph the demand and PV output for any chosen day. **Figure 2** is an example of these graphs, which also shows Tri-State's peak period, the times of sunrise and sunset, the peak demand, and a user defined reduced peak.

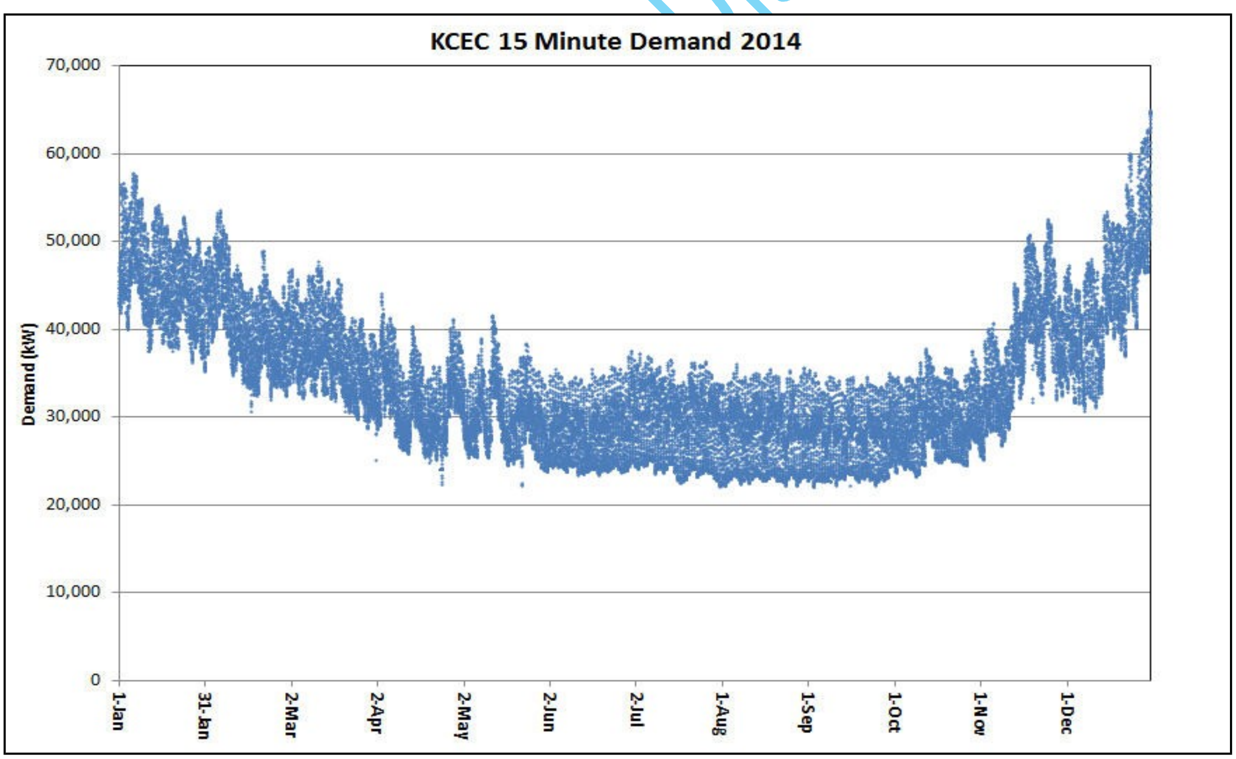

Figure 1. KCEC 15 Minute Demand for 2014.

Figure 2. KCEC 15 Minute Demand and PV Output for 30 December 2014.

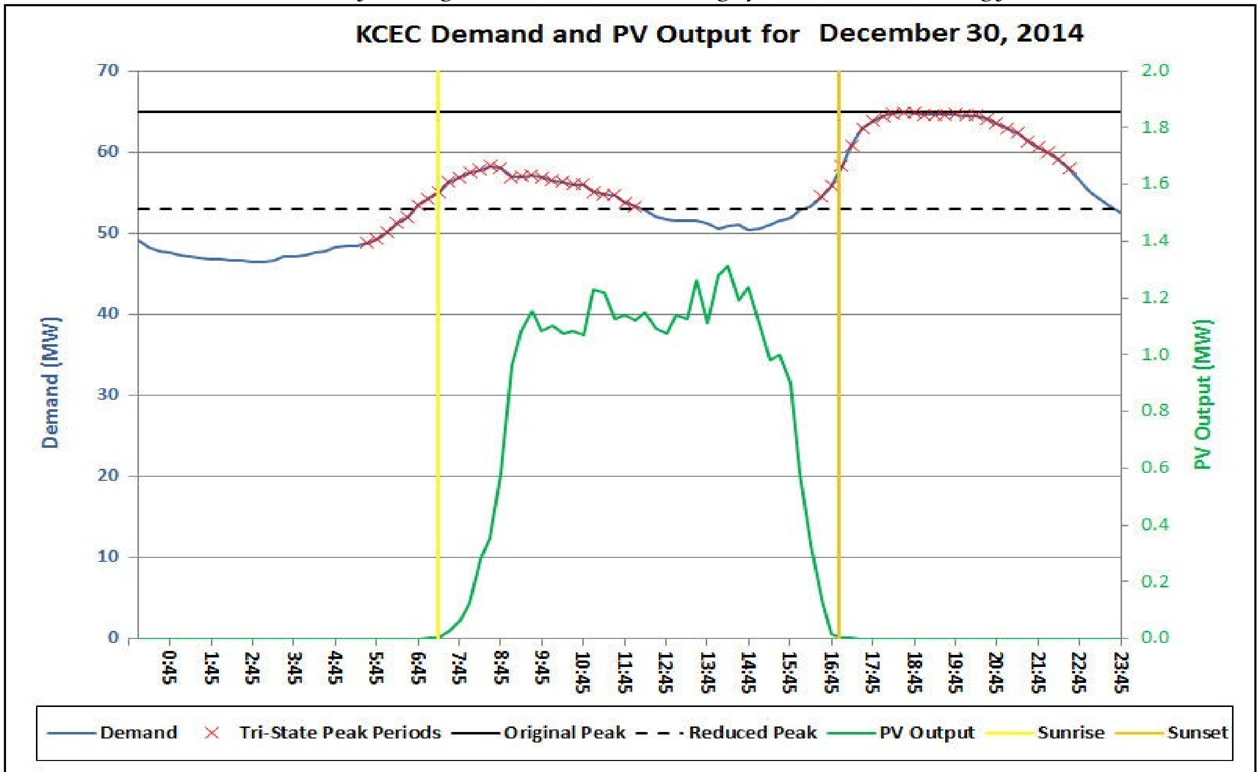

Figure 3. KCEC 15 Minute Demand during the Month of December 2014.

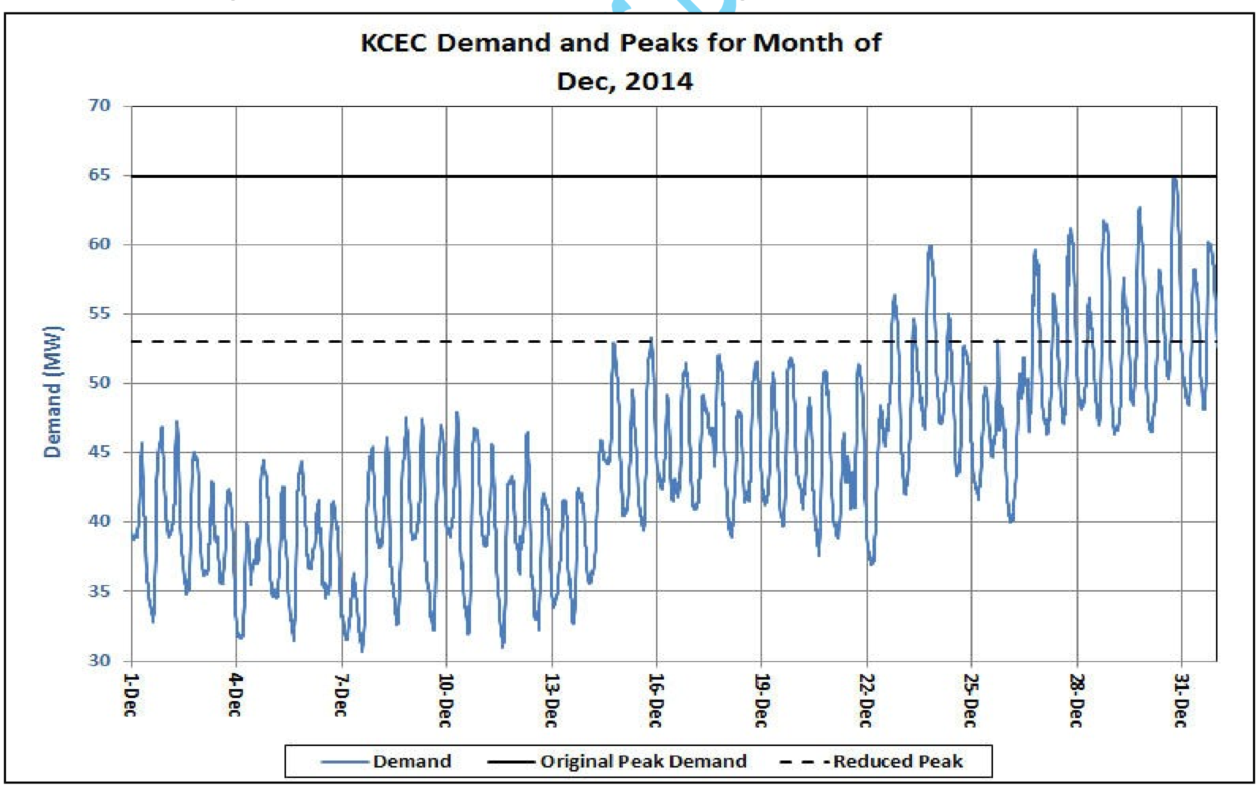

Figure 2 has very different left- and right-hand scales. On the left, demand is measured in tens of MWs. On the right, PV output is less than 2.5 MW. Today, PV is a very small percentage of demand, but the purpose of this report is to determine what may happen when renewable electricity

is a major part of demand. **Figure 2** shows Tri-State's two separate peak periods in the winter. The daily peak of KCEC demand occurs after sunset, as it does for most days of the year. The combination of the daily peak after sunset, and the strong annual peak in mid-winter is what is meant by the "extreme mismatch between KCEC's demand curve and the availability of solar radiation" in the first paragraph of this report.

The spreadsheet that produced **Figure 2** also allows the user to get rough estimates of the potential for reducing peak demand on any chosen day, the amount of storage capacity that would be required, and the resulting savings. For example, on December 30th (**Figure 2**), reducing peak demand from 64.94 MW to 53 MW would require 73.75 MWh. The demand reduction and the maximum power output of the storage facility would be 11.94 MW. The potential reduction in peak demand charges is thus $267,284 (11,943 kWh x 22.38 $/kWh) for the month of December. (Because the highest daily peak in December occurred on the 30th, it is assumed that all other December peaks can be kept below 53 MW.) The cost of 73.75 MWh at the assumed LCOE of 0.29 $/kWh is $21,388. Assuming that that the other days of December would use one-quarter this much energy on average, the cost of energy from storage would be $165,754. The net savings from using stored electricity to reduce peak demand charges would be $101,500.

Figure 3 shows KCEC's demand during the month of December 2014. Only 10 of the 31 days require any reduction to keep them below the chosen reduced peak of 53 MW. (Some days have two peaks - morning and evening, and should not be counted twice.) It is safe to assume that those ten days will require less energy to keep their peaks below 53 MW than 30 December. Thus, the assumption that the average December day will use 25% or less energy than 30 December seems reasonable.

The June 2014 day with the highest KCEC demand was June 30th. **Figure 4** shows that reducing its peak from 37.47 MW to 33 MW would require 16.3 MWh, and could save $99,950 for that month. The electricity from storage would cost $4,739, and if the average daily cost were half that, then the net saving would be $26,492. (**Figure 4** also shows the single Tri-State summer peak period from 7:00 am to 10:00 pm that is in effect during April through September.) **Figure 5** shows that for the month of June, every day would use some energy from storage to stay below 33 MW. These uses will all be smaller than the one for June 30th, so the assumption that the average day will need half as much seems reasonable.

The estimated potential savings in December are almost four times as much as those in June. This is mainly due to the fact that the monthly peak in December is much higher than the daily peaks during the rest of the month, while for June the daily peaks are much more even. This allows a lot of energy from storage to be used on the peak December day, cutting the monthly peak significantly, while using little or none during the other days, keeping the total amount of energy from storage low. In June, more similar amounts must be taken from storage every day, so the monthly peak is not cut as much, but the total energy from storage is higher. **Figure 1** shows that KCEC's peak demands are fairly constant during June through October, indicating fairly low

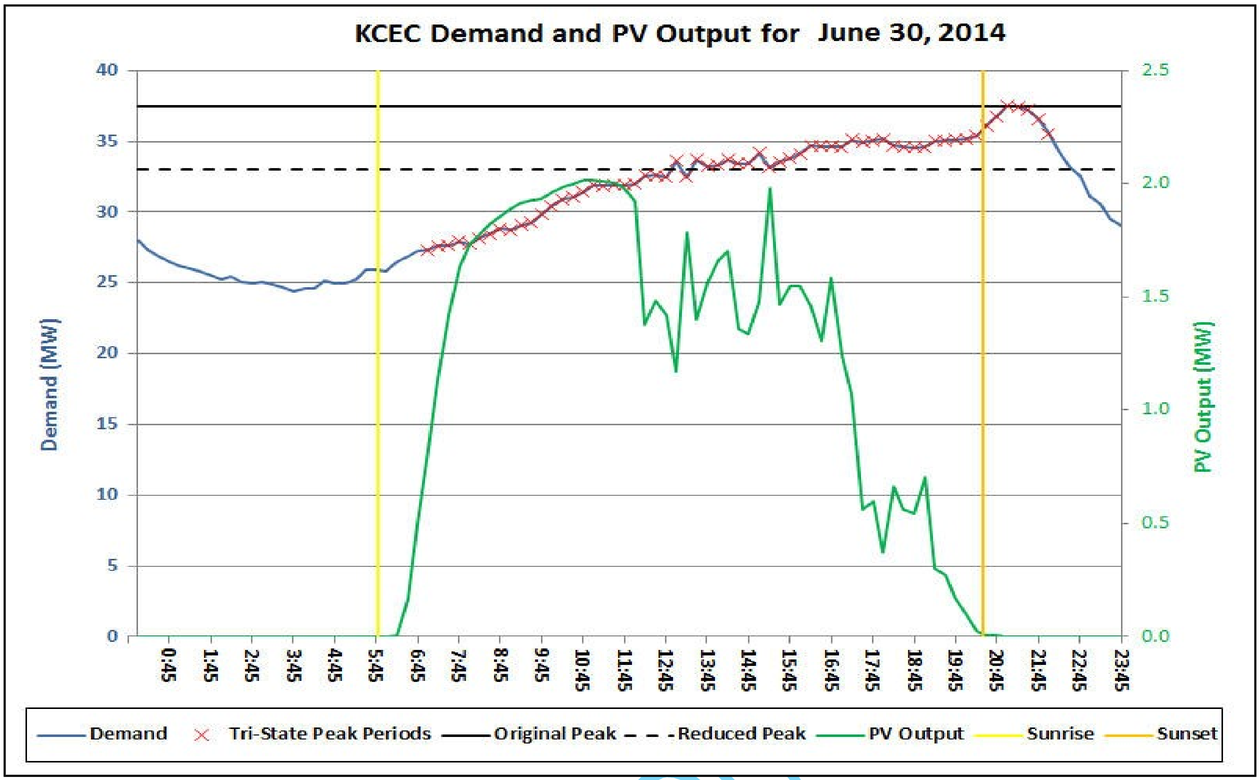

Figure 4. KCEC 15 Minute Demand and PV Output for 30 June 2014.

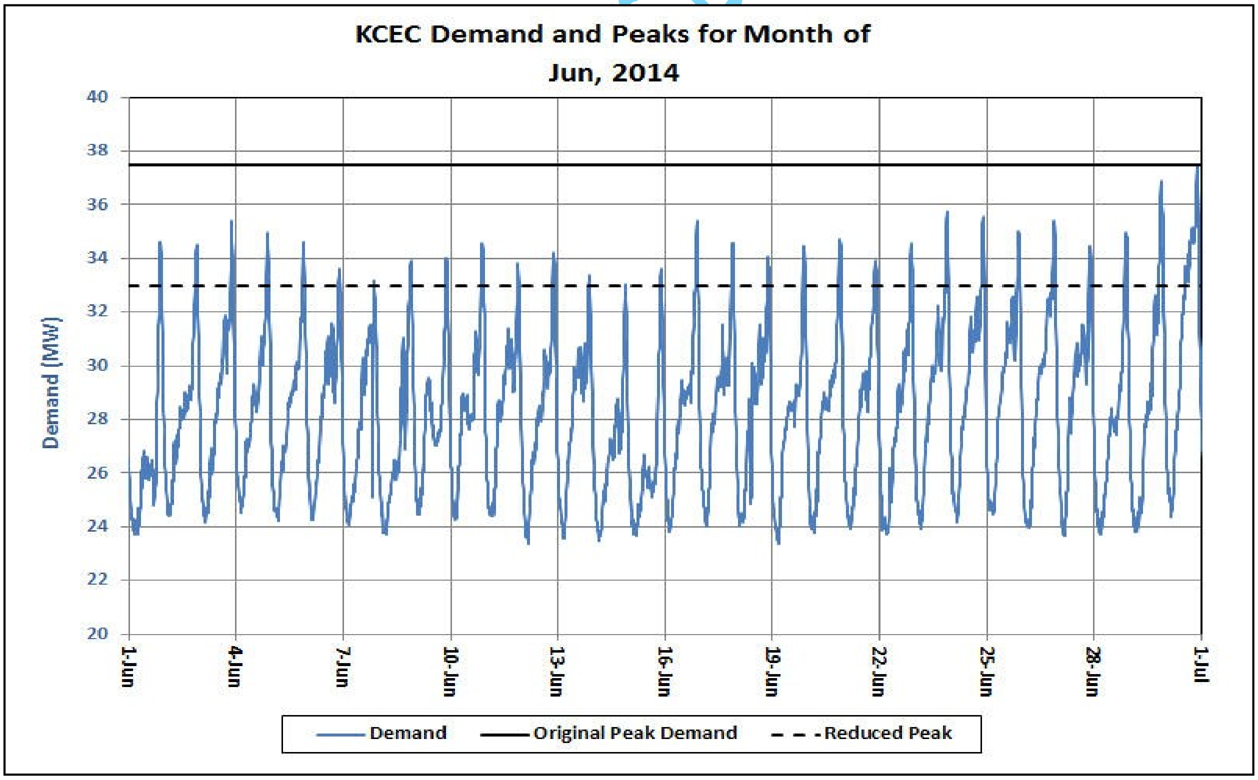

Figure 5. KCEC 15 Minute Demand during the Month of June 2014.

potentials for savings during those five months, and probably higher ones during the remaining seven months.

While this very preliminary analysis indicates potential monthly saving in the range of $25,000 to $100,000 per month, it also shows the need for a much more sophisticated and complete method for assessing savings, including the type of forecasting that would be used.

PV, Peak Demand Reduction, and Battery Charging:

Both **Figures 2 & 4** show significant amounts of PV generation during parts of the times when demand is being reduced. This PV electricity would help to reduce KCEC's demand (kWs purchased from Tri-State) during these times. However, PV can't be counted on to reduce peak demands, because on any given day there may be little or no PV generation during the peak periods. (The same applies to wind.)

PV also can't be counted on to charge the storage facility every day. So charging will have to be done by a combination of renewable and off-peak electricity. Using the maximum amount of renewable electricity for charging, and being sure that storage is fully charged before each peak period, will require forecasting the amount of renewable electricity that will be available at least one day ahead. When the forecast is for insufficient renewable electricity, then the storage facilities can be charged overnight, and/or during the gap between the two peak periods in winter. There will probably be days when the forecast peak demand is below peaks already recorded or expected later in the month. It would still be desirable to store excess renewable electricity for later use. This raises the issue of storage cost allocation. Every cycle of storage and release shortens the life of a storage facility. So when a cycle is used only for matching renewable supply with demand, that involves a cost that could be (partly) charged to renewable electricity rather than peak reductions. **Figures 3 & 5** indicate that this cost will vary considerably from month to month. A complete analysis should include the number and depth of such cycles, and their cost.

Diminishing Returns:

As illustrated in **Figures 2 & 4**, daily peak demands tend to occur during distinct peaking times. For example on December 30th (**Figure 2**), the peaking times could be considered to go from 6:45 am to noon, and from 4:30 to 10:30 pm. These are the times when demand is above 53 MW. Because the slopes of the peaking times are fairly steep, it is possible to make a significant reduction in the daily peak with a reasonable amount of energy (MWh) from storage. However, if one wanted to make further reductions in the daily peak, one would have to make them on flatter sections of the curve. This would require more storage energy for every MW of peak reduction, as shown in **Table 1**. The energy required is the energy capacity of the required storage facility; as it increases so does the cost of the facility. As the demand reduction per cost of storage decreases, so do the actual savings.

Desired Peak (MW)	Peak Reduction (MW)	Energy Required (MWh)	Reduction per MWh

62	2.943	8.832	0.34
60	4.943	17.206	0.29
58	6.943	27.593	0.25
55	9.943	51.811	0.19
53	11.943	73.750	0.16
50	14.943	109.823	0.14
48	16.943	135.338	0.13

Table 1. Diminishing Returns from Larger Peak Reductions.

An Algorithm for Estimating Potential Annual Savings:

In order to get a more accurate estimate of the potential savings from peak demand reduction, Renewable Taos is developing a computer program. This program will allow the user to enter the capacities (kW & kWh) for a storage facility, and will determine the maximum reduction for each month, as follows:

For each month:

> Find the maximum demand during a peak period, and the date and time at which it occurs.
>
> For the day of maximum demand, reduce the peak demand until one of the storage capacities is reached.
>
> For all the days of the month, determine how much energy must be taken from storage to reduce their peak demands to reduced peak of the day of maximum demand.

See the appendix for the complete algorithm.

Consequences of Miss-forecasting the Date, Size and Shape of the Monthly Peaks:

As mentioned, reasonably accurate forecasts of the size and shape of the maximum demand curve are needed to achieve savings that are close to the potentials for each month. **Figures 6 & 7** illustrate the consequences of a miss-forecast. **Figure 6** is an example of possible forecast and actual demand curves. If there were 12.5 MWh in storage, the forecast peak demand could have been reduced from 50 MW to 40 MW. The actual curve is 2 MW higher (52 v 50), stays above 40 MW for an additional 45 minutes, and would require 21.75 MWh to reduce it to 40 MW. (If correctly forecasted, it could have been reduced to 43.7 MW.) **Figure 7** shows that in attempting to reduce the actual demand to 40 MW, the available 12.5 MWh would be used up before the actual peak was reached at 20:30, so the peak of 52 MW would not have been reduced at all. If a situation like this occurs on the day of maximum demand for a monthly billing period, then peak demand charges for that month would not be reduced at all, no matter how well forecasted and reduced the other days of the month were. Over predicting a peak may not be as disastrous as under predicting, but can still result in a significant loss of potential savings.

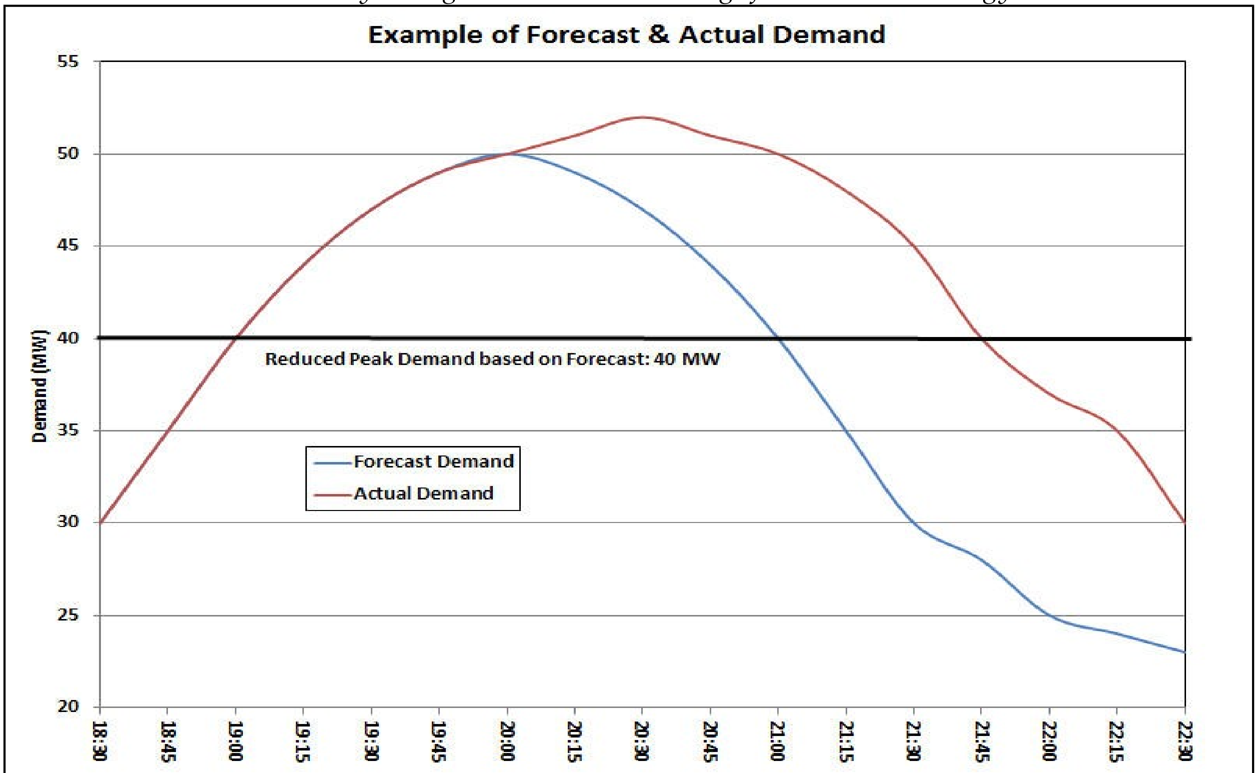

Figure 6. Possible Forecast and Actual Demand Curves.

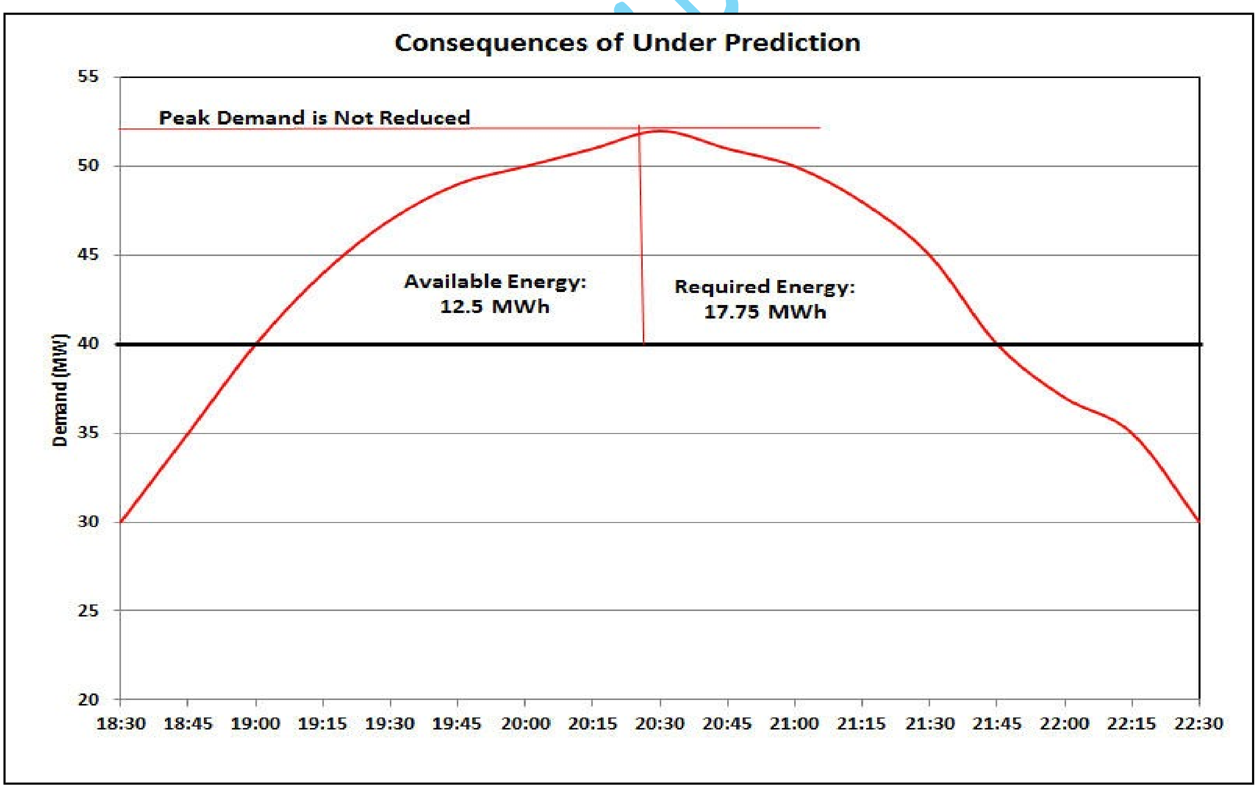

Figure 7. Possible Consequences of Under Predicting a Demand Curve.

Types of Storage Facilities:

At present, concentrating solar power with thermal energy storage (CSP TES) seems to be by far the lowest cost means of storing electricity. According to Lazard, the levelized cost of energy (LCOE) for CSP TES is 0.12 $/kWh, while for batteries it is 0.29 $/kWh, or more than twice as much. (The averages of the cost ranges are used.) However, there appear to be problems with siting CSP TES facilities that could be used for reducing demand charges in the KCEC service area. **Figure 8** shows that the best sites for CES in Taos County are close to the Colorado border. However, there are no transmission or distribution lines capable of carrying the needed MWs of power in that area. Also, in order to use CSP TES to reduce demand charges, it would be necessary to have backup power for those critical days when monthly peaks must be reduced, and sufficient direct normal radiation is not available. The best way to backup CSP TES is probably with natural gas, and this would involve running a large natural gas pipeline to the area. (It would be possible to charge (heat) a TES facility with off-peak electricity, but this would be about 30% efficient, compared with 80 – 90% efficiency for batteries.)

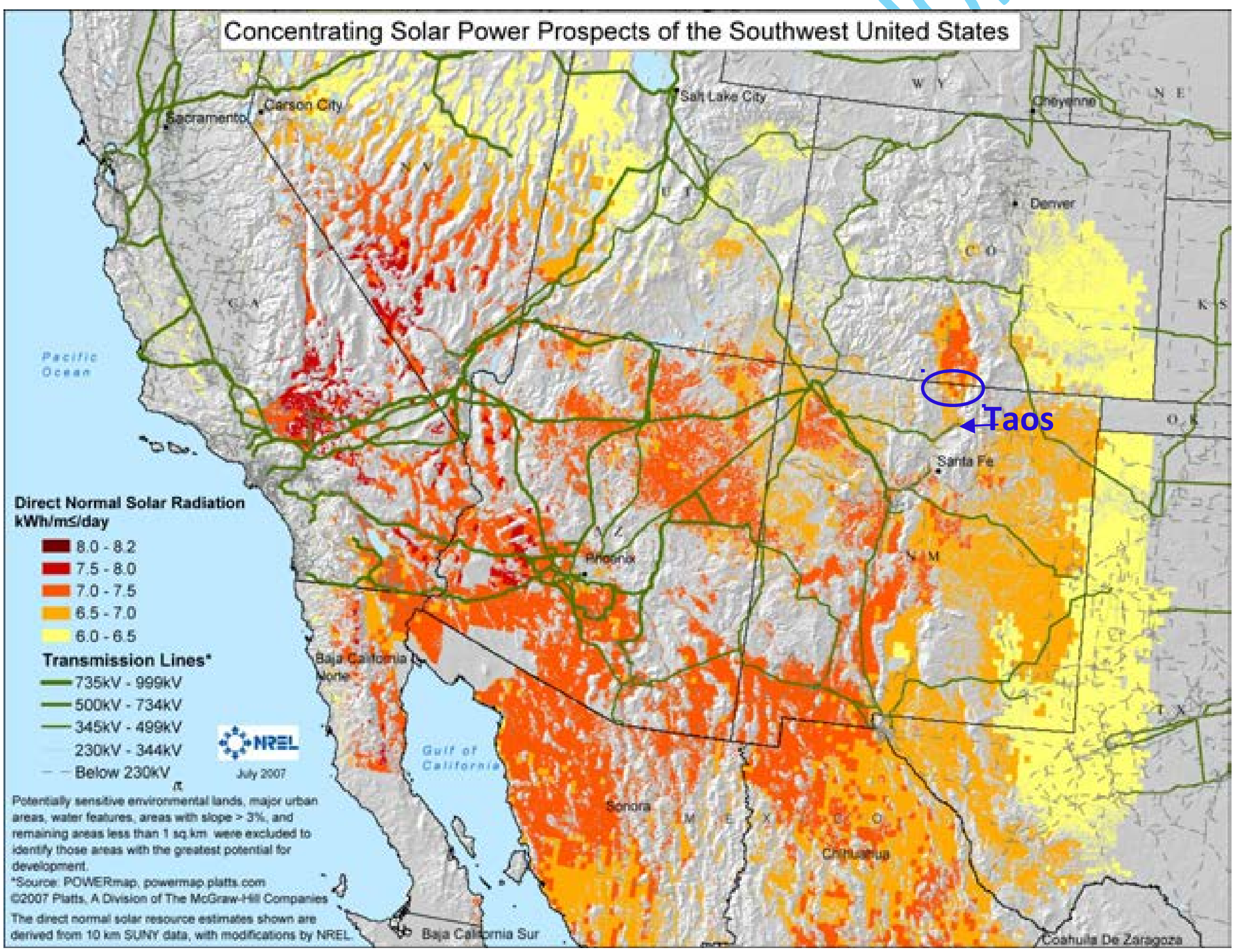

Figure 8. CSP TES Sites in the Southwest (NREL).

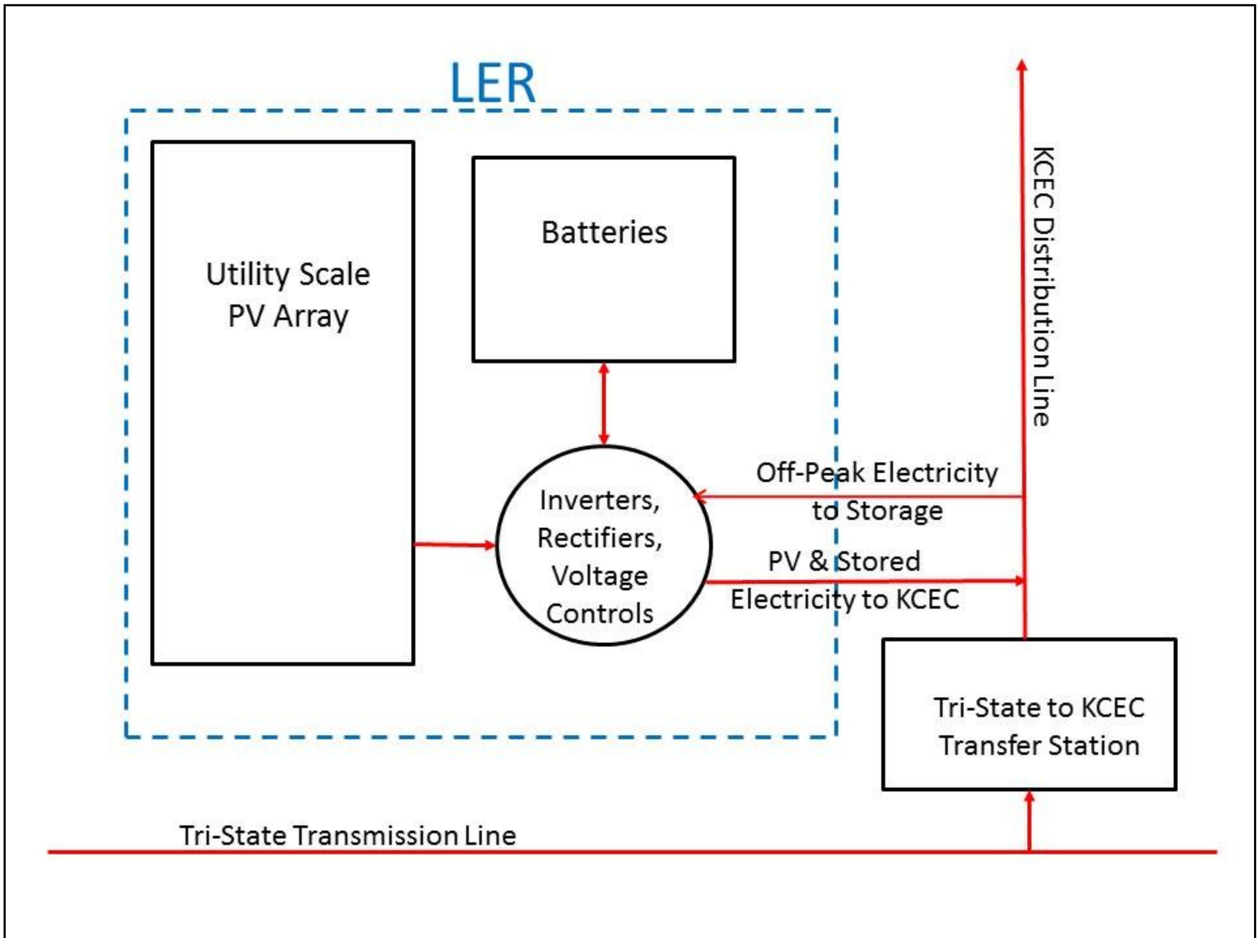

Figure 9, A Schematic for a Possible PV and Storage Facility.

CSP TES for KCEC should not be excluded from consideration, but the costs of less suitable sites closer to Taos, or of distribution and gas lines would have to be included in a comparison with the costs of a battery facility close to an existing substation. Batteries also have the advantage of being modular, while CSP TES seems to work best at scales close to 100 MW. So using batteries to reduce peak demand charges could be tried at a small scale, and expanded if successful. The costs of both types of storage are expected to drop, but battery costs may drop faster due to mass production. So, the most likely scenario for developing storage facilities for demand charge reductions appears to be starting with small-scale battery facilities, and expanding them as experience is gained and prices drop.

A Possible PV & Storage Facility:

Figure 9 is a simple schematic for a facility that includes utility-scale PV and storage. Such a facility could be owned and operated by KCEC, or by a separate entity like Land of Enchantment Renewables (?) (LER). LER could sign a PPA with KCEC to sell electricity at a fixed cost per kWh, would purchase off-peak electricity from KCEC when necessary, and would be compensated by KCEC for reducing peak demand payments. For example, LER could guarantee KCEC a certain amount of peak demand reduction for each month of the year, and LER could keep any additional reductions. LER could be responsible for reducing peak demand payments, and also for ensuring that all excess renewable energy generation is stored or curtailed.

LER would need real-time data on the amount of electricity being transferred from Tri-State to KCEC from all four transfer stations. This information would allow LER to determine when excess renewable electricity is being generated (total transfers from Tri-State are less than zero), and to store its PV generation, or curtail it if storage is full. It should be possible to fully automate LER's operations.

Conclusions:

This very preliminary study indicates that there is a significant potential for using storage of electricity to reduce peak demand payments from KCEC to Tri-State. The same storage facilities could also significantly expand the amount of renewable electricity that could be used within KCEC without the need to curtail or sell excess generation. More work is needed to verify these results, and the first step would be to implement the algorithm for estimating potential savings.

The End

Appendix: An Algorithm for Estimating Potential Annual Savings:

Arrays:

Demand(35040,2): The data: For each 15-min period of the year, the date & time, and the demand.
MthDay(12,2): First and last day each month. MthDay(1,1) =1, MthDay(1,2)=31, ...
MthMax(12,2): For each month, the date and time or max demand, and the max demand.
MthPeakRed(12): For each month, the reduced peak demand.
DayRedPow(12): For each month, the reduction in peak demand (kW).
DayRedEng(12): For each month, the amount of energy needed to reduce demand on peak day (kWh)

Inputs:

StorCapEng: The Energy Capacity of a Storage System (kWh)
StorCapPow: The Power Capacity of a Storage System (kW)

Program:

```
DecKW = 1                                   'Amount demand is reduced in each iteration (kW).
TotRedEng = 0                               'Total energy used for annual demand reduction (kWh).
FOR I = 1, 12                               'For each month
        FOR J = 1, 35040                    'Find starting and ending row for month
                IF (Demand(I,1) = MthDay(I,1) THEN MthStr = I
                IF (Demand(I,1) > MthDay(I,1) THEN
                        MthEnd =I
                        JUMP OUT OF FOR
                END IF
        END FOR
        MthMax(I,1) = MthMax(I,2) = 0                   'Find the date and time of max, and the
        max
        FOR J = MthStr, MthEnd                          'Peak Period demand for the month.
                PeakPer = 0                 'Is this a peak period?  Should be subroutine or GOTO.
                IF ((I >= 4) AND (I<=9) THEN        'Summer?  Apr thru Sep, 7:00an thru 10:00pm?
                        IF (TIME(Demand(J,1)>=7:00) AND (TIME(Demand(J,1)<=22:00) THEN
                                PeakPer = 1
                        END IF
                ELSE                        'Winter, 5:30am thru Noon, and 4:30pm thru 10:30pm
                        IF (TIME(Demand(J,1)>=7:30) AND (TIME(Demand(J,1)<=12:00) THEN
                        PeakPer = 1
                        IF (TIME(Demand(J,1)>=16:30) AND (TIME(Demand(J,1)<=22:30) THEN
                        PeakPer = 1
                END IF
                IF (PeakPer=1) THEN                             'Find date & time of monthly peak, and
                        IF (Demand(J,2)>MthMax(I,2)) THEN       'monthly peak
                                MthMax(I,1) = Demand(J,1)
                                MthMax(I,2) = Demand(J,2)
```

```
                END IF
        END IF
END FOR
FOR J = MthStr, MthEnd                       'Find first & last row of day with monthly max.
        IF (Demand(J,1)=DATE(MthMax(I,1)) THEN   'Match date of date&time w/ mthly max.
                DayStr = J
                DayEnd = J + 95
                JUMP OUT OF FOR
        END IF
END FOR

C:  For the day with the monthly max, loop thru the 15-minperiods of the day.  Each loop reduces
C:  the peak demand by 1 kW (DecKW), and calculates the energy needed to do so.
C:  Repeat until a Storage Capacity (StorCapEng or StorCapPow) is reached.
C:  The amount that the monthly peak demand is reduced to is MthPeakRed(I).
C:  The daily max minus this amount is the Storage Capacity (kW).
C:  For each hour that's in a Peak Period, if it is > MthPeakRed(I), then add  1 kW * 0.25 hours
C:  to the daily energy needed (DayRedEng(I).
DayRedEng(I) = DayRedPow(I) = 0
MthPeakRed(I) = MthMax(I,2) – DecKW
LOOP UNTIL ((DayRedEng>= StorCapEng) OR (DayRedPow>=StorCapPow))
        FOR J = DayStr, DayEnd
                Is this a peak period? (Sub or GOTO)
                IF (PeakPer=1) THEN
                        IF (Demand(J,2)>=MthMax(I)) THEN
                                DayRedPow(I) = Demand(J,2) – MthPeakRed(I)
                        END IF
                        IF (Demand(J,2)>=MthPeakRed(I) THEN
                                DayRedEng(I) = DayRedEng(I) + (DecKW * 0.25)
                        END IF
                END IF
        END FOR
        MthPeakRed(I) = MthPeakRed(I) – DecKW
END LOOP
C:  The demand that max day of month I can be reduced to is MthPeakRed(I).  Now loop thru all
C:  days of month I to find how much energy will be required to reduce all their peaks to
MthPeakRed(I).
MthRedEng(I) = 0
Peak = MthMax(I,2) – DecKW
LOOP UNTIL (Peak<= MthPeakRed(I))
        FOR J = MthStr, MthEnd
                Is this a peak period? (Sub or GOTO)
                IF (PeakPer=1) THEN
                        IF (Demand(J,2)>=Peak) THEN
                                MthRedEng(I) = MthRedEng(I) + (DecKW * 0.25)
                        END IF
```

```
                END IF
            END FOR
            Peak = Peak - DecKW
        END LOOP
        TotRedEng = TotRedEng + MthRedEng(I)               'Sum of Monthly Energy use
        PeakRedMth(I) = MthMax(I,2) - MthPeakRed(I)        'Amount monthly peak is reduced (kW).
END FOR
```

C: For each month, print: Name, Original Peak, Reduced Peak, Amount of Reduction, Storage Capacity Use (kW), Total Energy from Storage (kWh).

PRINT: Month, MthMax(I,2), MthPeakRed(I), PeakRedMth(I), DayRedPow(I), MthRedEng(I)