Initial Comments of the National Rural Electric Cooperative Association
Energy Conservation Standards for Distribution Transformers
Notice of Proposed Rulemaking
Docket No. EERE-2010-BT-STD-0048
RIN 1904-AC04
April 3, 2012

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to respond to the notice of proposed rulemaking (NOPR) issued by the U.S. Department of Energy (DOE) which addresses energy conservation standards for distribution transformers.[1]

NRECA is the national service organization for more than 900 not-for-profit rural electric utilities that provide electric energy to approximately 42 million consumers in 47 states or 13 percent of the nation's population. Kilowatt-hour (kWh) sales by rural electric cooperatives account for about 11 percent of all electric energy sold in the United States. NRECA members generate approximately 50 percent of the electric energy they sell and purchase the remaining 50 percent from non-NRECA members. The vast majority of NRECA members are non-for-profit, consumer-owned cooperatives. NRECA's members also include approximately 65 generation and transmission (G&T) cooperatives. The G&Ts are owned by the distribution cooperatives they serve. Remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. Both distribution and G&T cooperatives were formed to provide reliable electric service to their owner-members at the lowest reasonable cost.

These Initial Comments of NRECA focus on the life cycle cost (LCC) analysis for liquid immersed transformers and flaws in the methodology for analyzing the LCC savings and cost-effectiveness of higher efficiency distribution transformers. Additional NRECA comments addressing outstanding issues to this NOPR will be filed at a later time.

I. Summary of Comments

The life cycle cost (LCC) analysis of the proposed energy conservation standards for distribution transformers overstates the cost-effectiveness of proposed designs. The electricity cost used in the LCC Analysis is more than two times the wholesale power cost faced by distribution transformer owners. The demand charges in the LCC analysis are shown to collect excessive capacity costs over and above the capacity cost recovery that is included in the hourly energy market prices. As a result, NRECA recommends that the demand charges be eliminated in the LCC analysis in order to remove the analytical bias towards improved cost effectiveness and higher efficiency standards in the LCC savings measure.

[1] "Energy Conservation Program: Energy Conservation Standards for Distribution Transformers; Notice of proposed rulemaking and public meeting," 77 Federal Register 28 (February 10, 2012), pp. 7282-7381.

If the demand charges are not eliminated, then the cost of a single-cycle combustion turbine or combined-cycle unit should be used to compute the no load demand charge instead of the avoided cost of a coal-fired generation plant since new coal-fired plants are no longer the marginal capacity to meet new base load needs. Substituting these lower cost capacity resources results in a substantially lower demand charge for no load losses and appears to reduce the LCC savings and cost effectiveness of the alternative TSL designs.

NRECA requests that the DOE conduct a new analysis with more realistic electricity cost assumptions and use the new analysis results in the final decision in this rulemaking. The likely outcome of the requested analysis will either support the NOPR as proposed by DOE, or it may support a final rulemaking of no change from the present conservation standard. This additional analysis can be performed in a timely manner and not affect the October 1, 2012 date for the issuance of the final rule.

II. The Life Cycle Cost (LCC) Analysis Overstates the Cost-Effectiveness of Proposed Energy Conservation Standards for Distribution Transformers

DOE states in the NOPR under the subheading paragraphs of E. Energy Use Analysis on page 7320:

> The analysis for liquid-immersed transformers assumes that these are owned by utilities and uses hourly load and price data to estimate the energy, peak demand, and cost impacts of improved efficiency.
>
> The energy savings from more efficient distribution transformers are a small decrement to the total energy consumption. The hourly price reflects the cost of serving a small, marginal change in load, and is therefore the appropriate method to use to estimate the costs savings associated with energy savings. This is true for both coil losses and winding losses, and is independent of how the transformer owner pays for the bulk of their power purchases.

NRECA accepts the statements above as the proper and the correct method to use in the analysis.

However, in describing the key inputs for the life cycle cost and payback period analysis, DOE also states that electricity costs were “Derived from tariff-based and hourly based electricity prices. **Capacity costs provided extra value for reducing losses at peak** (emphasis added).”[2]

[2] NOPR at 7322.

DOE used the tariff-based electricity prices in the analysis of dry type transformers. The hourly based electricity prices, as DOE stated, is appropriate in the analysis of liquid immersed transformers used by utilities.

The DOE clearly states in the NOPR that hourly pricing is "the appropriate method" to be used for distribution transformer coil and winding loss analysis. However, the later DOE statement that "**Capacity costs provided extra value for reducing losses at peak"** creates an inconsistency of statements with one another. This inconsistency of the statements strongly demonstrates a bias in the DOE analysis which artificially increases the life cycle costs and life cycle savings. This bias becomes very evident upon a thorough review of the DOE analysis. This inconsistency, as NRECA believes it shows here in, results in overstated life cycle cost benefits and understated payback periods that should not be used to justify increased distribution transformer efficiency standards.

A. The Electricity Cost Used in the LCC Analysis Is More Than Two Times the Wholesale Power Cost Faced by Distribution Transformer Owners

DOE consultants continually refer to the fact that DOE analyses must be consistent with the DOE's own EIA Annual Energy Outlook (AEO). Referring to the AEO2011, end-use or retail electricity prices are 9.8 cents in 2016 (nominal cents per kWh).[3] The AEO also breaks out the prices by service category: generation (5.6 cents), transmission (0.9 cents), and distribution (3.3 cents). Summing the generation and transmission categories approximates the wholesale cost of power which is 6.5 cents/kWh. This price represents the average wholesale cost of electricity faced by distribution transformer owners.

In contrast, the average cost of power embodied in the DOE spreadsheet model computes to average annual 13.6 cents/kWh (believed to be 2016 cents/kWh).[4] As a result, the DOE average cost of power used to assess distribution transformer performance is more than two times the cost of power projected by the AEO.

B. The Demand Charges in the LCC Analysis Collect Excessive Capacity Costs

The demand and energy portion of the LCC methodology combines the energy charges and demand charges associated with transformer losses, plus an adder to account for maintenance cost, to calculate the annual operating cost of a transformer. DOE uses the Federal Energy Regulatory Commission (FERC) Form 714 hourly system lambda data and market prices in its analysis.[5] These prices are multiplied by the annual no load and load kWh losses to determine the cost of energy losses.

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[3] Annual Energy Outlook 2011, Energy Information Administration, U.S. Dept. of Energy, Electricity Supply, Disposition, Prices, and Emissions, http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2011&subject=0-AEO2011&table=8-AEO2011&region=0-0&cases=ref2011-d020911a.

[4] DOE NOPR spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, Forecast Cells tab. Operating cost of base transformer (less $17 maintenance charge) divided by the sum of no load and load kWh losses for the base transformer (cells L24 and L33).

[5] NOPR on p. 7320.

Assessing a demand cost for transformer load appears to be the means for capacity costs to provide "[…] extra value for reducing losses at peak."[6] The demand charge is computed by multiplying a given transformer's no load and load losses at peak by the avoided cost of new electric generating capacity.[7] The cost of a new coal-fired electricity generation plant is used to determine the demand charge for no load losses and the cost of a new combustion turbine is used as the basis for determining the demand charge for load losses.[8]

As stated above, the average cost of electricity used in the DOE analysis is 13.6 cents/kWh[9] and more than double the AEO wholesale generation price of 6.5 cents/kWh. The AEO price, which includes the recovery of fuel, generation capacity, transmission capacity, and a rate of return on investment, is generally consistent with the LCC analysis' cost of electricity used to price energy losses at 7 cents/kWh. This implies that the effect of the demand charge in the LCC analysis is to over collect capacity costs and increase average electricity costs on a $/kWh basis substantially above the wholesale price of electricity that transformers actually face.

NRECA believes that the average price of power used by DOE to calculate transformer operating costs should be consistent with projected prices in the AEO.

C. The Capacity Costs That the LCC Analysis Seeks to Recover in Demand Charges Are Already Recovered In the Hourly Energy Prices

The hourly energy prices used in the LCC analysis already account for the recovery of generation capacity costs. Demand charges to recover capacity costs are duplicative and overstate the cost of electric service. The hourly energy price data from the FERC Form 714 and markets represents the system lambda or marginal energy price. This is the $/megawatt-hour (MWh) cost (reflecting fuel cost and variable O&M) of the last generator set required to meet load, when generators are dispatched least cost to highest cost. During the peak hours of the day, the marginal energy price will be relatively high when compared to the price in non-peak periods. These marginal energy prices, over the course of 24 hours per day and 365 days per year, recover the system generation capacity costs.

Figure 1 provides an explanation of how this works. It depicts the supply and demand conditions in a large balancing area or market during hour 16 of a given day. The demand is 100,000 MWhs. The marginal cost of the last generator required to meet hourly demand is $100/MWh (10 cents/kWh). This is the selling price that all

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6 NOPR at 7322.

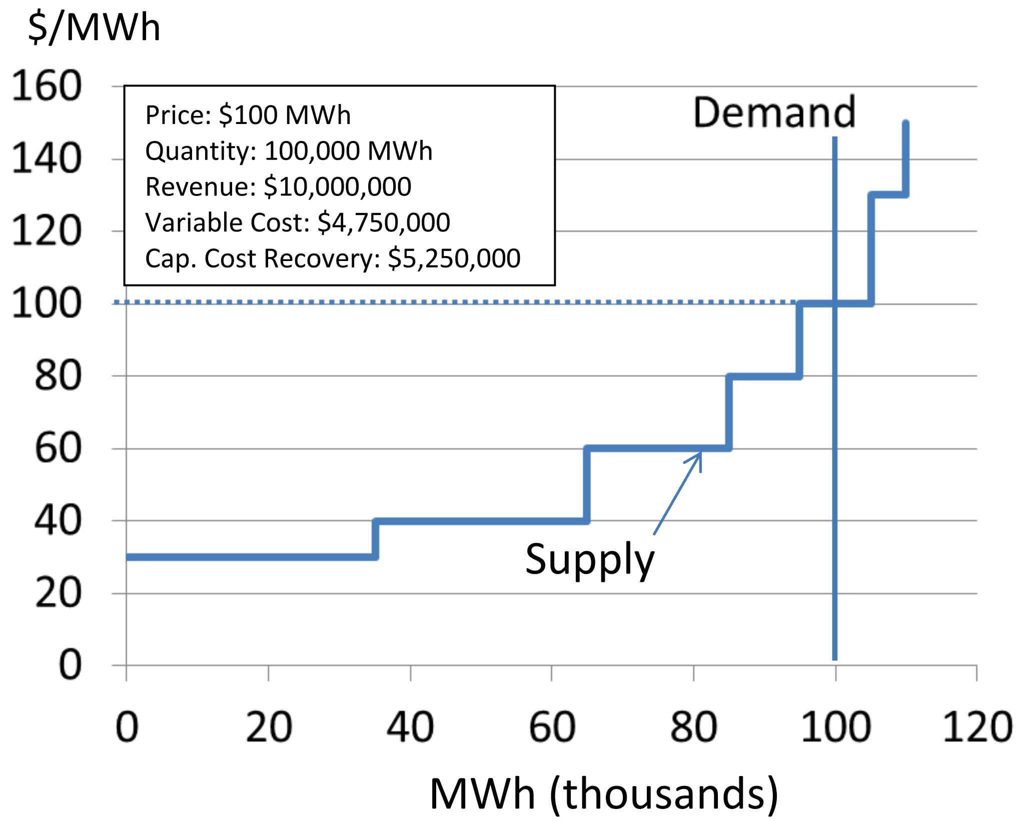
7 The avoided cost of new electric generating capacity ($/kW-year) is increased by a factor of 1.15 to account for reliability reserves and 1.08 to account for transmission and distribution losses.

8 The demand charge is based on the product of the unit cost of generation capacity cost and the incremental system capacity required by the load. See Transformer_Draft_TSD_Chapter8_version8-1-05 8/9/05, p. 8-18, p. 8-19.

9 All prices in this section are in nominal year 2016 dollars.

dispatched generators receive. Total revenues for this one hour of operation are $10 million. However, the sum of the variable costs of all dispatched generators is $4.75 million. The remaining $5.25 million goes toward the recovery of fixed capacity costs and profit. In this way, the FERC Form 714 hourly and market prices recover both variable and fixed capacity costs. Demand charges are not needed to collect capacity charges. These costs are already included in the hourly energy prices.[10] NRECA does not support assigning any demand charges for transformers when these costs are already being collected through marginal cost pricing.

Figure 1
Balancing Area/Marginal Cost Pricing
Hour 16



D. Comparison of Actual Wholesale Electricity Prices and the LCC Electricity Costs for the Rocky Mountain Region Confirms That the Electricity Costs in the LCC Analysis Are Too High

The NOPR's LCC and Payback Calc tab for Design Line 1 (DL1) spreadsheets presents data and calculations for the Rocky Mountain region of the U.S. The no load and the

[10] It is true that in some regions with RTO markets, load-serving entities (LSEs) pay for generation capacity through the purchase of capacity credits. Requiring LSEs to purchase capacity credits is seen by some as a means to bring more capacity to the market and thereby reduce price volatility – which is reflected in the FERC Form 714 hourly prices. It is important to note that the capacity prices in these markets are substantially less than the avoided cost of capacity used in the LCC analysis to compute no load loss demand charges. See DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, Capacity Cost tab, columns L and E.

load loss demand and energy costs per kWh are determined by dividing combined energy and demand charges by the respective annual kWh. The results show no load charges at 13.6 cents[11]/kWh and load loss charges at 6.3 cents[12]/kWh. This section develops a comparable market-based estimate for the wholesale price of electricity which includes all capacity costs.

Table 1 presents price data from the Intercontinental Exchange (ICE). It shows the annual average firm day-ahead hourly on-peak and off-peak energy prices for 2010 and 2011. On-peak and off-peak prices are in $/MWh and the average annual prices are in $/kWh for the major trading buses in the Western Interconnection of the U.S.[13] These annual firm prices are the average of hourly market prices for capacity, firming capacity and energy combined.

Table 1

Annual Average Firm Day-ahead Pricing by Location by Time of Day, $/MWh
Source: The Intercontinental Exchange TheIce.com

Year	Four Corners		Mid-C		Palo Verde		SP-15	
	Off-Peak	*On-Peak*	*Off-Peak*	*On-Peak*	*Off-Peak*	*On-Peak*	*Off-Peak*	*On-Peak*
2010	27.03	39.87	28.55	35.92	27.70	38.75	28.94	40.18
2011	20.59	36.44	16.40	29.09	21.58	36.12	21.71	36.82

Annual Average Firm Day-ahead Pricing by Location, $/kWh

Year	Four Corners	Mid-C	Palo Verde	SP-15
	Annual	*Annual*	*Annual*	*Annual*
2010	$0.0342	$0.0327	$0.0339	$0.0352
2011	$0.0295	$0.0235	$0.0297	$0.0302

The prices in Table 1 do not include transmission and distribution costs (or the associated losses and reserve margins used by DOE) required to deliver the power and energy to distribution transformers. These costs and the loss and reserve multipliers for the Rocky Mountain region are listed in the Capacity Cost tab of DOE's NOPR Design Line 1 spreadsheets.[14] Using the no load watts[15] and no load kWh/year[16], the average annual

[11] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & Payback Calc tab. Cells (W2+W5)/W7.
[12] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & Payback Calc tab. Cells (W4+W6)/W8.
[13] Mid C is Middle Columbia for delivery points in Washington and Oregon. SP-15 is South Path -15 for delivery points in California. Four Corners is for delivery points in Utah, Colorado, Arizona, and New Mexico. Palo Verde is for delivery points in Arizona, New Mexico, Southern Nevada, Southern California, Utah and Colorado.
[14] DOE NOPR spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, Capacity Cost tab, cells K29, S20, and N36.
[15] DOE NOPR spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & Payback Calc tab, cell E9.
[16] DOE NOPR spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & Payback Calc tab, cell W7.

transmission, reserves, and losses cost are calculated to be 0.5 cents/kWh for the Rocky Mountain region.

Total annual average firm day-ahead market prices, as shown in Table 1 for Palo Verde, which is a major trading bus for delivery in the Rocky Mountain region, are combined with costs of transmission, reserves, and losses computed above to derive the comparable Rocky Mountain region annual average firm day-ahead market prices of 3.9 cents/kWh for 2010 and 3.5 cents/kWh for 2011, a decrease of 10.26%. As a result, the actual firm hourly wholesale market rates for electricity, including all capacity costs, in the Rocky Mountain region are far lower than no load charges of 13.6 cents/kWh and load loss charges of 6.3 cents/kWh embodied in the LCC model for this region.

Using only the annual energy charges for the Rocky Mountain region from the LCC and Payback Calc tab of DOE's DL1 spreadsheets, without any demand charges, annual average no load energy charges are 5.6 cents/kWh[17] and the annual average load loss energy charges are 5.9 cents/kWh[18] for 2010 and 2011, respectively. Since those costs already exceed the hourly market rates which include the recovery of capacity costs, it is reasonable to remove all no load and load loss demand charges from the LCC and LCC savings calculations. With the above change made to the LCC and Payback Calc tab, the LCC Savings for CSL1 and CSL2 designs becomes substantially more negative, falling from -$183 and $444 with the artificial demand costs included, to -$1308 and -$681 without the extra demand costs, respectively. Negative costs indicate higher life cycle costs when compared to the base transformer.

E. Demand Charges in the LCC Analysis Should Be Eliminated to Remove the Bias Towards Improved Cost Effectiveness in the LCC Savings Measure

As seen above, the result of applying excessive demand charges to transformer losses overstates the LCC savings and cost-effectiveness measures of new transformer designs. After correcting the electricity costs by eliminating the over collection of capacity costs in the demand charge, the LCC savings deteriorate. Moreover, this bias in the LCC savings estimates raises questions about the viability of increasing distribution transformer efficiency beyond the current DOE minimum efficiency standard.

III. If the Demand Charges Are Not Eliminated in the LCC Analysis, Then the Cost of a Combustion Turbine or Combined-Cycle Unit Should Be Substituted for the Avoided Cost of a New Coal-Fired Power Plant When Computing the No Load Demand Charge

[17] DOE NOPR spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & Payback Calc tab, cells W2/W7.
[18] DOE NOPR spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & Payback Calc tab, cells W3/W8.

A. The Cost-Effectiveness Measure of Alternative TSL Transformer Designs is Very Sensitive to the Inclusion of the Avoided Costs of New Coal-Fired Electricity Generating Plants

In deriving the demand charge for no load losses, DOE multiplies the incremental generation capacity requirement of a transformer by the avoided cost of new generating capacity. To the extent new TSL designs reduce demand relative to the base transformer, the overall operating cost will decline for the TSL design relative to the base transformer. In all regions of the U.S. except New England and New York, the DOE model calculates the demand charge by using the avoided cost of a new coal unit at $560.39/kW-year.[19] This impracticable avoided cost assumption has a powerful effect on the overall analytical results by exerting an undue, positive effect on the LCC savings calculations for the TSL designs, making higher efficiency distribution transformers appear more cost-effective.

If DOE insists on covering transformer no load demand (watts) with a specific type of generating plant, we suggest that prices for a single-cycle combustion turbine or combined-cycle plant with appropriate low natural gas fuel costs be used in the analysis.

B. Coal-Fired Electric Generating Capacity Is Not the Marginal Unit for Serving Base Load

Because no load losses are a constant demand over all hours of the year, they fit being served as base load. Although NRECA supports the expansion of coal-fired electricity generating capacity, these plants are nearly impossible to permit and build. Current industry business-as-usual trends and regulatory permitting practices point to a decline in coal-fired generating capacity. According to the EIA AEO 2012, there are not any coal plants currently planned to be constructed after 2012. Moreover, from 2013-2035, the EIA AEO only projects 1.2 GW of new coal capacity additions or about 0.9% of the 137.4 GW of new electric generating capacity projected to be constructed over the 2013-2035 period. In addition, the AEO projects 28 GW of coal capacity will be retired over the period.[20] This points to a net decline of more than 26.8 GW of coal-fired generating capacity over the period. Also, the recently announced EPA rules on new coal-fired power plants CO_2 emissions will also eliminate typical coal-fired power plants as an option.

Gas-fired combustion turbines and combined cycle units are increasing being used to service base load today, as well as the meeting peaking load. The capacity cost of these units on a $/kW-year basis is similar for the low capacity factor combustion turbine and the higher capacity factor combined cycle unit.[21] Although the capacity costs of these

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[19] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, Capacity Cost tab, column E.

[20] Annual Energy Outlook 2012 Early Release, Energy Information Administration, Reference Case Table A9, http://www.eia.gov/forecasts/aeo/er/.

[21] A recent study found that the capacity cost of a new combustion turbine ranges between $111 to $134/kW-year and the capacity cost of a new combined-cycle unit ranges between $144 to $168/kW-month. All costs in nominal dollars for the year 2015. See “Cost of New Entry Estimates for Combustion Turbines and Combined-Cycle Plants in PJM, The Brattle Group, August 24, 2011. http://www.brattle.com/_documents/UploadLibrary/Upload971.pdf.

units are not explicitly defined in the in the LCC model, the avoided cost of capacity applied to load losses for some regions is priced at a cost of $158.71 kW-year.[22] This appears generally consistent with the cost of a new combustion turbine or combined cycle unit on a $/kW-year basis. Moreover, in regions with restructured wholesale markets, most RTOs have even lower average capacity rates. For example, DOE's NOPR spreadsheet indicates that the average capacity rates across six RTO areas range from $54.00/kW-year to $162.18/kW-year.[23]

C. Substituting the Capacity Cost of a Combustion Turbine/Combined-Cycle Plant for the Avoided Cost of a New Coal-Fired Plant Appears to Reduce the LCC Savings and Cost-Effectiveness of the Alternative TSL Transformer Designs

Substituting the annual cost of a gas-fired combustion turbine or combined-cycle plant adjusted for reserves and T&D losses (adjusted CT/CC cost) for the annual cost of a coal-fired generating unit adjusted for reserves and t&d losses (adjusted coal unit costs) for no load demand substantially reduces the life cycle costs and LCC savings of the distribution transformer and also has an increasing effect on the length of the payback period. In some cases, this causes the LCC savings measure of cost-effectiveness to turn negative.

For example, studies have been performed using the DOE spreadsheets for design line 1, 50 kVA[24] and the results for the Base, CSL1 and CSL2 follow. By changing the no load demand charge calculated from an adjusted coal unit cost to an adjusted CT/CC cost, the no load demand charge for the Base, CSL1 and CSL2 changes from $67.08, $70.09, and $25.47 to $19.00, $19.85, and $7.21, respectively, on the LCC & PB Calc tab.[25] The annual adjusted coal unit cost is $696.00 kW-yr[26] and the annual Adjusted CT/CC cost is $197.12 kW-yr[27] to meet no load demand as shown on the Capacity Costs tab as unadjusted $560.39 and $158.91 capacity rates respectively.

With only the above no load capacity change made, and not changing from the other original DOE operating and maintenance costs of the total annual cost including maintenance found in the LCC & PB Calc tab, the study results show the LCC savings for CSL1 will be -$148 and for CSL2 will be -$32. In contrast, DOE's Forecast tab[28] shows these savings at $36 and $641 for TSL1 and TSL2, respectively, using annual adjusted coal unit costs for the no load demand charge. If the same change as above is made to the no load demand charges in other spreadsheets for Design Lines 2 through 5, a reduction of life cycle costs and LCC savings will also occur.

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[22] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, Capacity Cost tab., column E.
[23] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, Capacity Cost tab., column L.
[24] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb.
[25] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & PB Calc tab, cells W5, X5, and Y5.
[26] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & PB Calc tab, cell F26.
[27] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, LCC & PB Calc tab, cell F27.
[28] DOE NOPR Spreadsheet dt-nopr-lcc-dl01-50kva.xlsb, Forecast tab, cells L105 and L106.

NRECA recognizes that the LCC & Payback Calc tab of NOPR spreadsheet and the above calculations only address the Rocky Mountain Area region of the U.S. and the Forecast tab presents mean values for all of the U.S. If DOE does not completely eliminate the demand charges in the LCC model as requested, then NRECA requests that a LCC analysis be performed for the capacity resource substitution detailed above, for all regions of the U.S. This will provide a more accurate assessment of the cost effectiveness of the proposed energy conservation standards for distribution transformers.

A. The NOPR Analysis Does Not Properly Combine the Costs for Capacity Resources with Fuel for Those Resources

The methodological approach taken in DOE's NOPR analysis is characterized by a fundamental flaw. It assigns the cost of new coal- or gas-fired capacity resources to satisfy the capacity requirements for decremental losses of distribution transformers. However, it assigns marginal firm energy prices from either the electricity market or from the next resource economically dispatched in a region to compute the cost of energy losses experienced by distribution transformers. This is not a utility practice. This approach embodied in the methodology leads to an overstatement of the value of the LCC and LCC savings for higher efficiency distribution transformers.

For example, utilities, particularly for no load losses, are not going to build a new coal-fired plant and then purchase firm energy from the market. Rather, a new power plant will require the purchase of low cost fuel for the plant. This is also applicable to the gas-fired capacity the LCC analysis uses for load losses. This capacity should be using low cost natural gas as the price of its fuel source. Matching new coal plants with the cost of coal and new gas-fired plants with the cost of natural gas would lead to far lower energy prices than shown in the LCC analysis.

NRECA believes that DOE should use the appropriate fuel costs with its capacity costs, if that is the method applied in the study. Alternatively, the appropriate energy costs from electricity markets that include capacity costs on an hourly basis can be used in the analysis. But a mixture of these approaches as used in the LCC analysis leads to an improper conclusion.

IV. Conclusion

These comments show that the LCC analysis used to support the NOPR exaggerates the savings that will be achieved by increasing the minimum efficiency requirements for distribution transformers used by utilities. While NRECA supports the method of hourly price and hourly loading as being appropriate, the NOPR analysis’s improper over collection of capacity costs to provide “extra value for reducing losses at peak” cannot be justified. The LCC analysis for the NOPR shows unrealistic demand and energy costs that are far in excess of AEO and market prices. Unfortunately, this approach results in imaginary savings that will never be realized and should not be used to set a National Minimum Efficiency Standard.

NRECA requests that the DOE conduct a new analysis with more realistic electricity cost assumptions and use the new analysis results in the final decision in this rulemaking. The likely outcome of the requested analysis will either support the NOPR as proposed by DOE, or it may support a final rulemaking of no change from the present minimum energy conservation standards that went into effect on January1, 2010 and significantly increased the efficiency of distribution transformers. This additional analysis can be performed in a timely manner and not affect the October 1, 2012 date for the issuance of the final rule.

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