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10 CFR Part 431

Energy Conservation Program: Energy Conservation Standards for Distribution Transformers; Proposed Rule

DEPARTMENT OF ENERGY

10 CFR Part 431

[Docket Number EERE–2010–BT–STD–0048]

RIN 1904–AC04

Energy Conservation Program: Energy Conservation Standards for Distribution Transformers

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Notice of proposed rulemaking and public meeting.

SUMMARY: The Energy Policy and Conservation Act of 1975 (EPCA), as amended, prescribes energy conservation standards for various consumer products and certain commercial and industrial equipment, including low-voltage dry-type distribution transformers, and directs the U.S. Department of Energy (DOE) to prescribe standards for various other products and equipment, including other types of distribution transformers. EPCA also requires DOE to determine whether more-stringent, amended standards would be technologically feasible and economically justified, and would save a significant amount of energy. In this notice, DOE proposes amended energy conservation standards for distribution transformers. The notice also announces a public meeting to receive comment on these proposed standards and associated analyses and results.

DATES: DOE will hold a public meeting on February 23, 2012, from 9 a.m. to 1 p.m., in Washington, DC. The meeting will also be broadcast as a Webinar. See section VII Public Participation for Webinar registration information, participant instructions, and information about the capabilities available to Webinar participants.

DOE will accept comments, data, and information regarding this notice of proposed rulemaking (NOPR) before and after the public meeting, but no later than April 10, 2012. See section VII Public Participation for details.

ADDRESSES: The public meeting will be held at the U.S. Department of Energy, Forrestal Building, Room 8E–089, 1000 Independence Avenue SW., Washington, DC 20585. To attend, please notify Ms. Brenda Edwards at (202) 586–2945. Please note that foreign nationals visiting DOE Headquarters are subject to advance security screening procedures. Any foreign national wishing to participate in the meeting should advise DOE as soon as possible by contacting Ms. Edwards to initiate the necessary procedures. In addition, persons can attend the public meeting via Webinar. For more information, refer to the Public Participation section near the end of this notice.

Any comments submitted must identify the NOPR for Energy Conservation Standards for Distribution Transformers, and provide docket number EERE–2010–BT–STD–0048 and/or regulation identifier number (RIN) number 1904–AC04. Comments may be submitted using any of the following methods:

1. *Federal eRulemaking Portal: www.regulations.gov*. Follow the instructions for submitting comments.
2. *Email: DistributionTransformers-2010-STD-0048@ee.doe.gov*. Include the docket number and/or RIN in the subject line of the message.
3. *Mail:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J, 1000 Independence Avenue SW., Washington, DC 20585–0121. If possible, please submit all items on a CD. It is not necessary to include printed copies.
4. *Hand Delivery/Courier:* Ms. Brenda Edwards, U.S. Department of Energy, Building Technologies Program, 950 L'Enfant Plaza SW., Suite 600, Washington, DC 20024. Telephone: (202) 586–2945. If possible, please submit all items on a CD, in which case it is not necessary to include printed copies.

Written comments regarding the burden-hour estimates or other aspects of the collection-of-information requirements contained in this proposed rule may be submitted to Office of Energy Efficiency and Renewable Energy through the methods listed above and by email to *Chad_S_Whiteman@omb.eop.gov*.

For detailed instructions on submitting comments and additional information on the rulemaking process, see section VII of this document (Public Participation).

Docket: The docket is available for review at *www.regulations.gov*, including **Federal Register** notices, framework documents, public meeting attendee lists and transcripts, comments, and other supporting documents/materials. A link to the docket Web page can be found at: *http://www.regulations.gov/#!docketDetail;rpp=10;po=0;D=EERE-2010-BT-STD-0048*.

FOR FURTHER INFORMATION CONTACT: James Raba, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Program, EE–2J, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 586–8654. Email: *Jim.Raba@ee.doe.gov*.

Ami Grace-Tardy, U.S. Department of Energy, Office of the General Counsel, GC–71, 1000 Independence Avenue SW., Washington, DC 20585–0121. Telephone: (202) 586–5709. Email: *Ami.Grace-Tardy@hq.doe.gov*.

SUPPLEMENTARY INFORMATION:

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I. Summary of the Proposed Rule

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Public Law 94–163 (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for ''Consumer Products Other Than Automobiles.'' Part C of Title III of EPCA (42 U.S.C. 6311–6317) established a similar program for ''Certain Industrial Equipment,'' including distribution transformers.[1] Pursuant to EPCA, any new or amended energy conservation standard that the Department of Energy (DOE) prescribes for certain equipment, such as distribution transformers, shall be designed to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A) and 6316(a)). Furthermore, the new or amended standard must result in a significant conservation of energy. (42 U.S.C. 6295(o)(3)(B) and 6316(a)). In accordance with these and other statutory provisions discussed in this notice, DOE proposes amended energy conservation standards for distribution transformers. The proposed standards are summarized in the following tables: Table I.1, through Table I.3 that describe the covered equipment classes and proposed trial standard levels (TSLs), Table I.4 that shows the mapping of TSL to energy efficiency levels (ELs),[2] and Table I.5 through Table I.8 which show the proposed standard in terms of minimum electrical efficiency. These proposed standards, if adopted, would apply to all covered distribution transformers listed in the tables and manufactured in, or imported into, the

[1] For editorial reasons, upon codification in the U.S. Code, Parts B and C were redesignated as Parts A and A–1, respectively.

[2] A detailed description of the mapping of trial standard level to energy efficiency levels can be found in the Technical Support Document, chapter 10 section 10.2.2.3 pg 10–10.

United States on or after January 1, 2016. As discussed in section IV.C.8 of this notice, any distribution transformer with a kVA rating falling between the kVA ratings shown in the tables shall meet a minimum energy efficiency level calculated by a linear interpolation of the minimum efficiency requirements of the kVA ratings immediately above and below that rating.[3]

TABLE I.1—PROPOSED ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS (COMPLIANCE STARTING JANUARY 1, 2016)

Equipment class	Design line	Type	Phase count	BIL	Proposed TSL
1	1, 2 and 3	Liquid-immersed	1	Any	1
2	4 and 5	Liquid-immersed	3	Any	1

Note: BIL means "basic impulse insulation level."

TABLE I.2—PROPOSED ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS (COMPLIANCE STARTING JANUARY 1, 2016)

Equipment class	Design line	Type	Phase count	BIL	Proposed TSL
3	6	Low-voltage, dry-type	1	≤10 kV	1
4	7 and 8	Low-voltage, dry-type	3	≤10 kV	1

Note: BIL means "basic impulse insulation level."

TABLE I.3—PROPOSED ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS (COMPLIANCE STARTING JANUARY 1, 2016)

Equipment class	Design line	Type	Phase count	BIL	Proposed TSL
5	9 and 10	Medium-voltage, dry-type	1	25–45 kV	2
6	9 and 10	Medium-voltage, dry-type	3	25–45 kV	2
7	11 and 12	Medium-voltage, dry-type	1	46–95 kV	2
8	11 and 12	Medium-voltage, dry-type	3	46–95 kV	2
9	13A and 13B	Medium-voltage, dry-type	1	≥96 kV	2
10	13A and 13B	Medium-voltage, dry-type	3	≥96 kV	2

Note: BIL means "basic impulse insulation level," and measures how resistant a transformer's insulation is to large voltage transients.

TABLE I.4—TRIAL STANDARD LEVEL TO ENERGY EFFICIENCY LEVEL MAPPING FOR PROPOSED ENERGY CONSERVATION STANDARD

Type	Design line	Phase count	Proposed TSL	Energy efficiency level
Liquid-immersed	1	1	1	1
	2	1		Base
	3	1		1
	4	3		1
	5	3		1
Low-voltage, dry-type	6	1	1	Base
	7	3		2
	8	3		2
Medium-voltage, dry-type	9	3	2	1
	10	3		2
	11	3		1
	12	3		2
	13A	3		1
	13B	3		2

[3] kVA is an abbreviation for kilovolt-ampere, which is a capacity metric used by industry to classify transformers. A transformer's kVA rating represents its output power when it is fully loaded (*i.e.,* 100 percent).

TABLE I.5—PROPOSED ELECTRICAL EFFICIENCIES FOR ALL LIQUID-IMMERSED DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES (COMPLIANCE STARTING JANUARY 1, 2016)

Standards by kVA and equipment class			
Equipment class 1		Equipment class 2	
kVA	%	kVA	%
10	98.70	15	98.65
15	98.82	30	98.83
25	98.95	45	98.92
37.5	99.05	75	99.03
50	99.11	112.5	99.11
75	99.19	150	99.16
100	99.25	225	99.23
167	99.33	300	99.27
250	99.39	500	99.35
333	99.43	750	99.40
500	99.49	1000	99.43
		1500	99.48

TABLE I.6—PROPOSED ELECTRICAL EFFICIENCIES FOR ALL LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES (COMPLIANCE STARTING JANUARY 1, 2016)

Standards by kVA and equipment class			
Equipment class 3		Equipment class 4	
kVA	%	kVA	%
15	97.73	15	97.44
25	98.00	30	97.95
37.5	98.20	45	98.20
50	98.31	75	98.47
75	98.50	112.5	98.66
100	98.60	150	98.78
167	98.75	225	98.92
250	98.87	300	99.02
333	98.94	500	99.17
		750	99.27
		1000	99.34

TABLE I.7—PROPOSED ELECTRICAL EFFICIENCIES FOR ALL MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES (COMPLIANCE STARTING JANUARY 1, 2016)

Standards by kVA and equipment class											
Equipment class 5		Equipment class 6		Equipment class 7		Equipment class 8		Equipment class 9		Equipment class 10	
kVA	%	kVA	%	kVA	%	kVA	%	kVA	%	kVA	%
15	98.10	15	97.50	15	97.86	15	97.18				
25	98.33	30	97.90	25	98.12	30	97.63				
37.5	98.49	45	98.10	37.5	98.30	45	97.86				
50	98.60	75	98.33	50	98.42	75	98.13				
75	98.73	112.5	98.52	75	98.57	112.5	98.36	75	98.53		
100	98.82	150	98.65	100	98.67	150	98.51	100	98.63		
167	98.96	225	98.82	167	98.83	225	98.69	167	98.80	225	98.57
250	99.07	300	98.93	250	98.95	300	98.81	250	98.91	300	98.69
333	99.14	500	99.09	333	99.03	500	98.99	333	98.99	500	98.89
500	99.22	750	99.21	500	99.12	750	99.12	500	99.09	750	99.02
667	99.27	1000	99.28	667	99.18	1000	99.20	667	99.15	1000	99.11
833	99.31	1500	99.37	833	99.23	1500	99.30	833	99.20	1500	99.21
		2000	99.43			2000	99.36			2000	99.28
		2500	99.47			2500	99.41			2500	99.33

A. Benefits and Costs to Consumers [4]

Table I.8 presents DOE's evaluation of the economic impacts of the proposed standards on customers of distribution transformers, as measured by the average life-cycle cost (LCC) savings and the median payback period (PBP). DOE measures the impacts of standards relative to a base case that reflects likely trends in the distribution transformer market in the absence of amended standards. The base case predominantly consists of products at the baseline efficiency levels evaluated for each representative unit, which correspond to the existing energy conservation standard level of efficiency for distribution transformers established either in DOE's 2007 rulemaking or by EPACT 2005. The average LCC savings are positive for all but two of the design lines, for which customers are not impacted by the proposed standards. (Throughout this document, ''distribution transformers'' are also referred to as simply ''transformers.'')

TABLE I.8—IMPACTS OF PROPOSED STANDARDS ON CUSTOMERS OF DISTRIBUTION TRANSFORMERS

Design Line	Average LCC savings (2010$)	Median payback period (years)
Liquid-Immersed		
1	36	20.2
2	* N/A	* N/A
3	2,413	6.3
4	862	5.0
5	7,787	4.0
Low-Voltage, Dry-Type		
6	* N/A	* N/A
7	1,714	4.5
8	2,476	8.4
Medium-Voltage, Dry-Type		
9	849	2.6
10	4,791	8.8
11	1,043	10.7
12	6,934	9.0
13A	25	16.5
13B	4,709	12.5

* No consumers are impacted by the proposed standard because no change from the minimum efficiency standard is proposed for design lines 2 and 6.

B. Impact on Manufacturers

The industry net present value (INPV) is the sum of the discounted cash flows to the industry from the base year through the end of the analysis period (2011 through 2045). Using a real discount rate of 7.4 percent for liquid-immersed distribution transformers, 9 percent for medium-voltage dry-type distribution transformers, and 11.1 percent for low-voltage dry- type distribution transformers, DOE estimates that the industry net present value (INPV) for manufacturers of liquid-immersed, medium-voltage dry-type and low-voltage dry-type distribution transformers is $625 million, $91 million, and $220 million, respectively, in 2011$. Under the proposed standards, DOE expects that liquid-immersed manufacturers may lose up to 6.3 percent of their INPV, which is approximately $39.6 million; medium-voltage manufacturers may lose up to 7.1 percent of their INPV, which is approximately $6.5 million; and low-voltage dry-type manufacturers may lose up to 7.7 percent of their INPV, which is approximately $16.8 million. Additionally, based on DOE's interviews with the manufacturers of distribution transformers, DOE does not expect any plant closings or significant loss of employment.

C. National Benefits

DOE's analyses indicate that the proposed standards would save a significant amount of energy—an estimated 1.58 quads over 30 years (2016–2045). In addition, DOE expects the energy savings from the proposed standards to be equivalent to the energy output from 2.40 gigawatts (GW) of generating capacity by 2045.

The cumulative national net present value (NPV) of total consumer costs and savings of the proposed standards for distribution transformers sold in 2016–2045, in 2010$, ranges from $2.9 billion (at a 7-percent discount rate) to $12.2 billion (at a 3-percent discount rate) over 30 years (2016–2045). This NPV expresses the estimated total value of future operating cost savings minus the estimated increased equipment costs for distribution transformers purchased in 2016–2045, discounted to 2010.

In addition, the proposed standards would have significant environmental benefits. The energy savings are expected to result in cumulative greenhouse gas emission reductions of 122.1 million metric tons (Mt) [5] of carbon dioxide (CO_2) from 2016–2045. During this period, the proposed standards are expected to result in emissions reductions of 99.7 thousand tons of nitrogen oxides (NO_X) and 0.819 tons of mercury (Hg).[6]

The value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 (otherwise known as the Social Cost of Carbon, or SCC) developed by a recent interagency process. The derivation of the SCC values is discussed in section IV.M. DOE estimates the net present monetary value of the CO_2 emissions reduction is between $0.71 and $12.5 billion, expressed in 2010$ and discounted to 2010. DOE also estimates the net present monetary value of the NO_X emissions reduction, expressed in 2010$ and discounted to 2010, is between $0.069 billion at a 7-percent discount rate and $0.210 billion at a 3-percent discount rate.[7]

Table I.9 summarizes the national economic costs and benefits expected to result from today's proposed standards for distribution transformers.

[4] For the purposes of this document, the ''consumers'' of distribution transformers are referred to as ''customers.'' Customers refer to electric utilities in the case of liquid-immersed transformers, and to utilities and building owners in the case of dry-type transformers.

[5] A metric ton is equivalent to 1.1 short tons. A short ton is equal to 2,000 pounds. Results for NO_X and Hg are presented in short tons (referred to here as simply ''tons.'')

[6] DOE calculates emissions reductions relative to the most recent version of the Annual Energy Outlook (AEO) Reference case forecast. This forecast accounts for emissions reductions from in-place regulations, including the Clean Air Interstate Rule (CAIR, 70 FR 25162 (May 12, 2005)), but not the Clean Air Mercury Rule (CAMR, 70 FR 28606 (May 18, 2005)). Subsequent regulations, including the Cross-State Air Pollution rule issued on July 6, 2011, do not appear in the AEO forecast at this time.

[7] DOE is aware of multiple agency efforts to determine the appropriate range of values used in evaluating the potential economic benefits of reduced Hg emissions. DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it once again monetizes Hg in its rulemakings.

TABLE I.9—SUMMARY OF NATIONAL ECONOMIC BENEFITS AND COSTS OF PROPOSED DISTRIBUTION TRANSFORMER ENERGY CONSERVATION STANDARDS

Category	Present value *billion 2010$*	Discount rate (percent)
Benefits:		
Operating Cost Savings	5.58	7
	17.44	3
CO_2 Reduction Monetized Value (at $4.9/t) *	0.71	5
CO_2 Reduction Monetized Value (at $22.3/t) *	4.13	3
CO_2 Reduction Monetized Value (at $36.5/t) *	7.20	2.5
CO_2 Reduction Monetized Value (at $67.6/t) *	12.54	3
NO_X Reduction Monetized Value (at $2,537/ton) *	0.069	7
	0.210	3
Total Benefits**	9.78	7
	21.7	3
Costs:		
Incremental Installed Costs	2.67	7
	5.21	3
Net Benefits:		
Including CO_2 and NO_X	7.10	7
	16.5	3

* The CO_2 values represent global monetized values of the SCC in 2010 under several scenarios. The values of $4.9, $22.1, and $36.3 per metric ton (t) are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.1/t represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. A metric ton is equivalent to 1.1 short tons. A short ton is equal to 2,000 pounds. Results for NO_X are presented in short tons (referred to here as simply "tons.")

** Total Benefits for both the 3% and 7% cases are derived using the SCC value calculated at a 3% discount rate, and the average of the low and high NO_X values used in DOE's analysis.

The benefits and costs of today's proposed standards, for equipment sold in 2016–2045, can also be expressed in terms of annualized values. The annualized monetary values are the sum of: (1) The annualized national economic value of the benefits from consumer operation of equipment that meets the proposed standards (consisting primarily of operating cost savings from using less energy minus increases in equipment purchase and installation costs, which is another way of representing consumer NPV), and (2) the annualized monetary value of the benefits of emission reductions, including CO_2 emission reductions.[8]

Although combining the values of operating savings and CO_2 emission reductions provides a useful perspective, two issues should be considered. First, the national operating savings are domestic U.S. consumer monetary savings that occur as a result of market transactions while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and CO_2 savings are performed with different methods that use different time frames for analysis. The national operating cost savings is measured for the lifetime of distribution transformers shipped in 2016–2045. The SCC values, on the other hand, reflect the present value of some future climate-related impacts resulting from the emission of one metric ton of carbon dioxide in each year. These impacts continue well beyond 2100.

Estimates of annualized benefits and costs of today's proposed standards are shown in Table I.10. (All monetary values below are expressed in 2010$.) The results under the primary estimate are as follows. Using a 7-percent discount rate for benefits and costs other than CO_2 reduction, for which DOE used a 3-percent discount rate along with the SCC series corresponding to a value of $22.3/metric ton in 2010, the cost of the standards proposed in today's proposed standards is $302 million per year in increased equipment costs. The benefits are $631 million per year in reduced equipment operating costs, $244 million in CO_2 reductions, and $7.78 million in reduced NO_X emissions. In this case, the net benefit amounts to $581 million per year. Using a 3-percent discount rate for all benefits and costs and the SCC series corresponding to a value of $22.3/metric ton in 2010, the cost of the standards proposed in today's rule is $308 million per year in increased equipment costs. The benefits are $1,026 million per year in reduced operating costs, $244 million in CO_2 reductions, and $12.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $975 million per year.

TABLE I.10—ANNUALIZED BENEFITS AND COSTS OF PROPOSED STANDARDS FOR DISTRIBUTION TRANSFORMERS

	Discount rate	Monetized (million 2010$/year)		
		Primary estimate *	Low net benefits estimate *	High net benefits estimate *
Benefits:				

[8] DOE used a two-step calculation process to convert the time-series of costs and benefits into annualized values. First, DOE calculated a present value in 2011, the year used for discounting the NPV of total consumer costs and savings, for the time-series of costs and benefits using discount rates of 3 and 7 percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE used a range of discount rates, as shown in Table I.9. From the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in 2011 that yields the same present value. The fixed annual payment is the annualized value. Although DOE calculated annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined would be a steady stream of payments.

TABLE I.10—ANNUALIZED BENEFITS AND COSTS OF PROPOSED STANDARDS FOR DISTRIBUTION TRANSFORMERS—Continued

	Discount rate	Monetized (million 2010$/year)		
		Primary estimate *	Low net benefits estimate *	High net benefits estimate *
Operating Cost Savings	7%	631	594	659.
	3%	1,026	950	1,075.
CO_2 Reduction at $4.9/t**	5%	58.6	58.6	58.6.
CO_2 Reduction at $22.3/t**	3%	244	244	244.
CO_2 Reduction at $36.5/t**	2.5%	389	389	389.
CO_2 Reduction at $67.6/t**	3%	742	742	742.
NO_X Reduction at $2,537/ton**	7%	7.78	7.78	7.78.
	3%	12.4	12.4	12.4.
Total †	7% plus CO_2 range	697 to 1380	660 to 1343	726 to 1409.
	7%	883	846	911.
	3% plus CO_2 range	1097 to 1780	1021 to 1704	1146 to 1829.
	3%	1,283	1,207	1,331.
Costs:				
Incremental Product Costs	7%	302	338	285.
	3%	308	351	289.
Total Net Benefits:				
Total †	7% plus CO_2 range	400 to 1083	327 to 1010	445 to 1128.
	7%	581	507	626.
	3% plus CO_2 range	789 to 1472	670 to 1353	857 to 1540.
	3%	975	855	1,043.

* The Primary, Low Net Benefits, and High Net Benefits Estimates utilize forecasts of energy prices from the *AEO 2011* reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect no change in the Primary estimate, rising product prices in the Low Net Benefits estimate, and declining product prices in the High Net Benefits estimate.

** The CO_2 values represent global values (in 2010$) of the social cost of CO_2 emissions in 2010 under several scenarios. The values of $4.9, $22.3, and $36.5 per metric ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6 per metric ton represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The value for NOX (in 2010$) is the average of the low and high values used in DOE's analysis.

Total Benefits for both the 3% and 7% cases are derived using the SCC value calculated at a 3% discount rate, which is $22.3/metric ton in 2010 (in 2010$). In the rows labeled as "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

DOE has tentatively concluded that the proposed standards represent the maximum improvement in energy efficiency that is technologically feasible and economically justified, and would result in the significant conservation of energy. DOE further notes that equipment achieving these proposed standard levels are already commercially available for at least some, if not most, equipment classes covered by today's proposal. Based on the analyses described above, DOE has tentatively concluded that the benefits of the proposed standards to the Nation (energy savings, positive NPV of consumer benefits, consumer LCC savings, and emission reductions) would outweigh the burdens (loss of INPV for manufacturers and LCC increases for some consumers).

DOE also considered more stringent energy efficiency levels as trial standard levels, and is still considering them in this rulemaking. However, DOE has tentatively concluded that, in some cases, the potential burdens of the more stringent energy efficiency levels would outweigh the projected benefits. Based on consideration of the public comments DOE receives in response to this notice and related information collected and analyzed during the course of this rulemaking effort, DOE may adopt energy efficiency levels presented in this notice that are either higher or lower than the proposed standards, or some combination of energy efficiency level(s) that incorporate the proposed standards in part.

II. Introduction

The following section briefly discusses the statutory authority underlying today's proposal, as well as some of the relevant historical background related to the establishment of energy conservation standards for distribution transformers.

A. Authority

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Public Law 94–163 (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for "Consumer Products Other Than Automobiles." Part C of Title III of EPCA (42 U.S.C. 6311–6317) established a similar program for "Certain Industrial Equipment," including distribution transformers.[9] The Energy Policy Act of 1992 (EPACT 1992), Public Law 102–486, amended EPCA and directed the Department to prescribe energy conservation standards for distribution transformers. (42 U.S.C. 6317(a)) The Energy Policy Act of 2005 (EPACT 2005), Public Law 109–25, amended EPCA to establish energy conservation standards for low-voltage, dry-type distribution transformers.[10] (42 U.S.C. 6295(y)) Under 42 U.S.C. 6313(a)(6)(C)(i), DOE must review energy conservation standards for commercial and industrial equipment and amend the standards as needed no later than six years from the issuance of a final rule establishing or amending a standard for a covered product. A final rule establishing any amended standards based on such notice of

[9] For editorial reasons, upon codification in the U.S. Code, Parts B and C were redesignated as Parts A and A–1, respectively

[10] EPACT 2005 established that the efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2007 shall be the Class I Efficiency Levels for distribution transformers specified in Table 4–2 of the "Guide for Determining Energy Efficiency for Distribution Transformers" published by the National Electrical Manufacturers Association (NEMA TP 1–2002).

proposed rulemaking (NOPR) must be completed within two years of publication of the NOPR. (42 U.S.C. 6313(a)(6)(C)(iii)(I)).

DOE publishes today's proposed rule pursuant to Part C of Title III, which establishes an energy conservation program for covered equipment that consists essentially of four parts: (1) Testing; (2) labeling; (3) the establishment of Federal energy conservation standards; and (4) compliance certification and enforcement procedures. For those distribution transformers for which DOE determines that energy conservation standards are warranted, the DOE test procedures must be the ''Standard Test Method for Measuring the Energy Consumption of Distribution Transformers'' prescribed by the National Electrical Manufacturers Association (NEMA TP 2–1998), subject to review and revision by the Secretary in accordance with certain criteria and conditions. (42 U.S.C. 6293(b)(10), 6314(a)(2)–(3) and 6317(a)(1)) Manufacturers of covered equipment must use the prescribed DOE test procedure as the basis for certifying to DOE that their equipment complies with the applicable energy conservation standards adopted under EPCA and when making representations to the public regarding the energy use or efficiency of those types of equipment. (42 U.S.C. 6314(d)) The DOE test procedures for distribution transformers currently appear at title 10 of the Code of Federal Regulations (CFR) part 431, subpart K, appendix A.

DOE must follow specific statutory criteria for prescribing amended standards for covered equipment. As indicated above, any amended standard for covered equipment must be designed to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A) and 6316(a)) Furthermore, DOE may not adopt any amended standard that would not result in the significant conservation of energy. (42 U.S.C. 6295(o)(3) and 6316(a)) Moreover, DOE may not prescribe a standard: (1) For certain equipment, including distribution transformers, if no test procedure has been established for the equipment, or (2) if DOE determines by rule that the proposed standard is not technologically feasible or economically justified. (42 U.S.C. 6295(o)(3)(A)–(B) and 6316(a)) In deciding whether a proposed amended standard is economically justified, DOE must determine whether the benefits of the standard exceed its burdens. (42 U.S.C. 6295(o)(2)(B)(i) and 6316(a)) DOE must make this determination after receiving comments on the proposed standard, and by considering, to the greatest extent practicable, the following seven factors:

1. The economic impact of the standard on manufacturers and consumers of the equipment subject to the standard;

2. The savings in operating costs throughout the estimated average life of the covered equipment in the type (or class) compared to any increase in the price, initial charges, or maintenance expenses for the covered products that are likely to result from the imposition of the standard;

3. The total projected amount of energy, or as applicable, water, savings likely to result directly from the imposition of the standard;

4. Any lessening of the utility or the performance of the covered equipment likely to result from the imposition of the standard;

5. The impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from the imposition of the standard;

6. The need for national energy and water conservation; and

7. Other factors the Secretary of Energy (Secretary) considers relevant. (42 U.S.C. 6295(o)(2)(B)(i) and 6316(a))

EPCA, as codified, also contains what is known as an ''anti-backsliding'' provision, which prevents the Secretary from prescribing any amended standard that either increases the maximum allowable energy use or decreases the minimum required energy efficiency of a covered product. (42 U.S.C. 6295(o)(1) and 6316(a)) Also, the Secretary may not prescribe an amended or new standard if interested persons have established by a preponderance of the evidence that the standard is likely to result in the unavailability in the United States of any covered product type (or class) of performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as those generally available in the United States. (42 U.S.C. 6295(o)(4) and 6316(a))

Further, EPCA, as codified, establishes a rebuttable presumption that an energy conservation standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing equipment complying with the energy conservation standard will be less than three times the value of the energy savings a consumer will receive in the first year of using the equipment. (See 42 U.S.C. 6295(o)(2)(B)(iii) and 6316(a))

Additionally, 42 U.S.C. 6295(q)(1), as applied to covered equipment via 42 U.S.C. 6316(a), specifies requirements when promulgating a standard for a type or class of covered equipment that has two or more subcategories. DOE must specify a different standard level than that which applies generally to such type or class of equipment for any group of covered equipment that has the same function or intended use if DOE determines that equipment within such group (A) consumes a different kind of energy from that consumed by other covered equipment within such type (or class); or (B) has a capacity or other performance-related feature which other equipment within such type (or class) does not have and such feature justifies a higher or lower standard. (42 U.S.C. 6294(q)(1) and 6316(a)) In determining whether a performance-related feature justifies a different standard for a group of equipment, DOE must consider such factors as the utility to the consumer of the feature and other factors DOE deems appropriate. *Id.* Any rule prescribing such a standard must include an explanation of the basis on which such higher or lower level was established. (42 U.S.C. 6295(q)(2) and 6316(a))

Federal energy conservation requirements generally supersede State laws or regulations concerning energy conservation testing, labeling, and standards. (42 U.S.C. 6297(a)–(c) and 6316(a)) DOE may, however, grant waivers of Federal preemption for particular State laws or regulations, in accordance with the procedures and other provisions set forth under 42 U.S.C. 6297(d)).

DOE has also reviewed this regulation pursuant to Executive Order (EO) 13563, issued on January 18, 2011 (76 FR 3281, Jan. 21, 2011). EO 13563 is supplemental to and explicitly reaffirms the principles, structures, and definitions governing regulatory review established in EO 12866. To the extent permitted by law, agencies are required by EO 13563 to: (1) Propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

DOE emphasizes as well that EO 13563 requires agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. In its guidance, the Office of Information and Regulatory Affairs has emphasized that such techniques may include identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes. For the reasons stated in the preamble, DOE believes that today's notice of proposed rulemaking (NOPR) is consistent with these principles, including the requirement that, to the extent permitted by law, benefits justify costs and that net benefits are maximized.

B. Background

1. Current Standards

On August 8, 2005, the Energy Policy Act of 2005 (EPACT 2005) amended EPCA to establish energy conservation standards for low-voltage, dry-type distribution transformers (LVDTs).[11] (EPACT 2005, Section 135(c); 42 U.S.C. 6295(y)) The standard levels for low-voltage dry-type distribution transformers appear in Table II.1.

TABLE II.1—FEDERAL ENERGY EFFICIENCY STANDARDS FOR LOW-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
15	97.7	15	97.0
25	98.0	30	97.5
37.5	98.2	45	97.7
50	98.3	75	98.0
75	98.5	112.5	98.2
100	98.6	150	98.3
167	98.7	225	98.5
250	98.8	300	98.6
333	98.9	500	98.7
		750	98.8
		1000	98.9

Note: Efficiencies are determined at the following reference conditions: (1) for no-load losses, at the temperature of 20 °C, and (2) for load-losses, at the temperature of 75 °C and 35 percent of nameplate load.

DOE incorporated these standards into its regulations, along with the standards for several other types of products and equipment, in a final rule published on October 18, 2005. 70 FR 60407, 60416—60417. These standards appear at 10 CFR 431.196(a).

On October 12, 2007, DOE published a final rule that established energy conservation standard for liquid-immersed distribution transformers and medium-voltage dry-type distribution transformers, which are shown in Table II.2 and Table II.3, respectively. 72 FR 58190, 58239–40. These standards are codified at 10 CFR 431.196(b) and (c).

TABLE II.2—ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.62	15	98.36
15	98.76	30	98.62
25	98.91	45	98.76
37.5	99.01	75	98.91
50	99.08	112.5	99.01
75	99.17	150	99.08
100	99.23	225	99.17
167	99.25	300	99.23
250	99.32	500	99.25
333	99.36	750	99.32
500	99.42	1000	99.36
667	99.46	1500	99.42
833	99.49	2000	99.46
		2500	99.49

Note: All efficiency values are at 50 percent of nameplate-rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, subpart K, appendix A.

[11] EPACT 2005 established that the efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2007 shall be the Class I Efficiency Levels for distribution transformers specified in Table 4–2 of the ''Guide for Determining Energy Efficiency for Distribution Transformers'' published by the National Electrical Manufacturers Association (NEMA TP 1–2002).

TABLE II.3—ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS

Single-phase				Three-phase			
BIL	20–45 kV	46–95 kV	≥96 kV	BIL	20–45 kV	46–95 kV	≥96 kV
kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)	kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.10	97.86		15	97.50	97.18	
25	98.33	98.12		30	97.90	97.63	
37.5	98.49	98.30		45	98.10	97.86	
50	98.60	98.42		75	98.33	98.12	
75	98.73	98.57	98.53	112.5	98.49	98.30	
100	98.82	98.67	98.63	150	98.60	98.42	
167	98.96	98.83	98.80	225	98.73	98.57	98.53
250	99.07	98.95	98.91	300	98.82	98.67	98.63
333	99.14	99.03	98.99	500	98.96	98.83	98.80
500	99.22	99.12	99.09	750	99.07	98.95	98.91
667	99.27	99.18	99.15	1000	99.14	99.03	98.99
833	99.31	99.23	99.20	1500	99.22	99.12	99.09
				2000	99.27	99.18	99.15
				2500	99.31	99.23	99.20

Note: BIL means "basic impulse insulation level."
Note: All efficiency values are at 50 percent of nameplate rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, subpart K, appendix A.

2. History of Standards Rulemaking for Distribution Transformers

In a notice published on October 22, 1997 (62 FR 54809), DOE stated that it had determined that energy conservation standards were warranted for electric distribution transformers, relying in part on two reports by DOE's Oak Ridge National Laboratory (ORNL). These reports—*Determination Analysis of Energy Conservation Standards for Distribution Transformers,* ORNL–6847 (1996) and *Supplement to the ''Determination Analysis,''* ORNL–6847 (1997)—are available on the DOE Web site at: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html.* In 2000, DOE issued its Framework Document for Distribution Transformer Energy Conservation Standards Rulemaking, describing its proposed approach for developing standards for distribution transformers, and held a public meeting to discuss the Framework Document. The document is available on the above-referenced DOE Web site. Stakeholders also submitted written comments on the document, addressing a range of issues.

Subsequently, DOE issued draft reports as to certain of the key analyses contemplated by the Framework Document.[12] It received comments from stakeholders on these draft reports and, on July 29, 2004, published an advance notice of proposed rulemaking (ANOPR) for distribution transformer standards. 69 FR 45376. DOE then held a webcast on material it had published relating to the ANOPR, followed by a public meeting on the ANOPR on September 28, 2004. In August 2005, DOE issued a draft of certain of the analyses on which it planned to base the standards for liquid-immersed and medium-voltage, dry-type distribution transformers, along with documents that supported the draft analyses.[13] DOE did this to enable stakeholders to review the analyses and make recommendations as to standard levels.

On April 27, 2006, DOE published its Final Rule on Test Procedures for Distribution Transformers. The rule: (1) Established the procedure for sampling and testing distribution transformers so that manufacturers can make representations as to their efficiency, as well as establish that they comply with Federal standards; and (2) contained enforcement provisions, outlining the procedure the Department would follow should it initiate an enforcement action against a manufacturer. 71 FR 24972 (codified at 10 CFR 431.198).

On August 4, 2006, DOE published a NOPR in which it proposed energy conservation standards for distribution transformers (the 2006 NOPR). 71 FR 44355. Concurrently, DOE also issued a technical support document (TSD) that incorporated the analyses it had performed for the proposed rule, including several spreadsheets that remain available on DOE's Web site.[14]

Some commenters asserted that DOE's proposed standards might adversely affect replacement of distribution transformers in certain space-constrained (*e.g.,* vault) installations. In response, DOE issued a notice of data availability and request for comments on this and another issue. 72 FR 6186 (Feb. 9, 2007) (the NODA). In the NODA, DOE sought comment on whether it should include in the LCC analysis potential costs related to size constraints of distribution transformers installed in vaults. DOE also outlined different approaches as to how it might account for additional installation costs for these space-constrained applications and requested comments on linking energy efficiency levels for three-phase liquid-immersed units with those of single-phase units. Finally, DOE addressed how it was inclined to consider a final standard that is based on energy efficiency levels derived from trial standard level (TSL) 2 and TSL 3 for three-phase units and TSLs 2, 3 and 4 for single-phase units. 72 FR 6189. Based on comments on the 2006 NOPR, and the NODA, DOE created new TSLs to address the treatment of three-phase units and single-phase units. In October 2007, DOE published a final rule that created the current energy conservation standards for liquid-immersed and medium-voltage dry-type distribution transformers. 72 FR 58190 (October 12,

[12] Copies of all the draft analyses published before the ANOPR are available on DOE's Web site: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers_draft_analysis.html*.

[13] Copies of the four draft NOPR analyses published in August 2005 are available on DOE's Web site: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers_draft_analysis_nopr.html*.

[14] The spreadsheets developed for this rulemaking proceeding are available at: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers_draft_analysis_nopr.html*.

2007) (the 2007 Final Rule) (codified at 10 CFR 431.196(b)–(c)).

The above paragraphs summarize development of the 2007 Final Rule. The preamble to the rule included additional, detailed background information on the history of that rulemaking. 72 FR 58194–96.

After the publication of the 2007 Final Rule, certain parties filed petitions for review in the United States Courts of Appeals for the Second and Ninth Circuits, challenging the rule. Several additional parties were permitted to intervene in support of these petitions. (All of these parties are referred to below collectively as ''petitioners.'') The petitioners alleged that, in developing its energy conservation standards for distribution transformers, DOE did not comply with certain applicable provisions of EPCA and of the National Environmental Policy Act (NEPA), as amended (42 U.S.C. 4321 *et seq.*) DOE and the petitioners subsequently entered into a settlement agreement to resolve the petitions. The settlement agreement outlined an expedited timeline for the Department to determine whether to amend the energy conservation standards for liquid-immersed and medium-voltage dry-type distribution transformers. Under the original settlement agreement, DOE was required to publish by October 1, 2011, either a determination that the standards for these distribution transformers do not need to be amended or a NOPR that includes any new proposed standards and that meets all applicable requirements of EPCA and NEPA. Under an amended settlement agreement, the October 1, 2011, deadline for a DOE determination or proposed rule was extended to February 1, 2012. If DOE finds that amended standards are warranted, DOE must publish a final rule containing such amended standards by October 1, 2012.

On March 2, 2011, DOE published in the **Federal Register** a notice of public meeting and availability of its preliminary TSD for the Distribution Transformer Energy Conservation Standards Rulemaking, wherein DOE discussed and received comments on issues such as equipment classes of distribution transformers that DOE would analyze in consideration of amending the energy conservation standards for distribution transformers, the analytical framework, models and tools it is using to evaluate potential standards, the results of its preliminary analysis, and potential standard levels. 76 FR 11396. The notice is available on the above-referenced DOE Web site. To expedite the rulemaking process, DOE began at the preliminary analysis stage because it believes that many of the same methodologies and data sources that were used during the 2007 rulemaking rule remain valid. On April 5, 2011, DOE held a public meeting to discuss the preliminary TSD. Representatives of manufacturers, trade associations, electric utilities, energy conservation organizations, Federal regulators, and other interested parties attended this meeting. In addition, other interested parties submitted written comments about the TSD addressing a range of issues. These comments are discussed in the following sections of the NOPR.

On July 29, 2011, DOE published in the **Federal Register** a notice of intent to establish a subcommittee under the Energy Efficiency and Renewable Energy Advisory Committee (ERAC), in accordance with the Federal Advisory Committee Act and the Negotiated Rulemaking Act, to negotiate proposed Federal standards for the energy efficiency of medium-voltage dry-type and liquid immersed distribution transformers. 76 FR 45471. Stakeholders strongly supported a consensual rulemaking effort. DOE believed that, in this case, a negotiated rulemaking would result in a better informed NOPR and would minimize any potential negative impact of the NOPR. On August 12, 2011, DOE published in the **Federal Register** a similar notice of intent to negotiate proposed Federal standards for the energy efficiency of low-voltage dry-type distribution transformers. 76 FR 50148. The purpose of the subcommittee was to discuss and, if possible, reach consensus on a proposed rule for the energy efficiency of distribution transformers.

The ERAC subcommittee for medium-voltage liquid-immersed and dry-type distribution transformers consisted of representatives of parties having a defined stake in the outcome of the proposed standards, listed below.

- ABB Inc.
- AK Steel Corporation
- American Council for an Energy-Efficient Economy
- American Public Power Association
- Appliance Standards Awareness Project
- ATI-Allegheny Ludlum
- Baltimore Gas and Electric
- Cooper Power Systems
- Earthjustice
- Edison Electric Institute
- Fayetteville Public Works Commission
- Federal Pacific Company
- Howard Industries Inc.
- LakeView Metals
- Efficiency and Renewables Advisory Committee member
- Metglas, Inc.
- National Electrical Manufacturers Association
- National Resources Defense Council
- National Rural Electric Cooperative Association
- Northwest Power and Conservation Council
- Pacific Gas and Electric Company
- Progress Energy
- Prolec GE
- U.S. Department of Energy

The ERAC subcommittee for medium-voltage liquid-immersed and dry-type distribution transformers held meetings on September 15 through 16, 2011, October 12 through 13, 2011, November 8 through 9, 2011, and November 30 through December 1, 2011; the ERAC subcommittee also held public webinars on November 17 and December 14. During the course of the September 15, 2011, meeting, the subcommittee agreed to its rules of procedure, ratified its schedule of the remaining meetings, and defined the procedural meaning of consensus. The subcommittee defined consensus as unanimous agreement from all present subcommittee members. Subcommittee members were allowed to abstain from voting for an efficiency level; their votes counted neither toward nor against the consensus.

DOE presented its draft engineering, life-cycle cost and national impacts analysis and results. During the meetings of October 12 through 13, 2011, DOE presented its revised analysis and heard from subcommittee members on a number of topics. During the meetings on November 8 through 9, 2011, DOE presented its revised analysis, including life-cycle cost sensitivities based on exclusion ZDMH and amorphous steel as core materials. During the meetings on November 30 through December 1, 2011, DOE presented its revised analysis based on 2011 core-material prices.

At the conclusion of the final meeting, subcommittee members presented their efficiency level recommendations. For medium-voltage liquid-immersed distribution transformers, the advocates, represented by the Appliance Standards Awareness Project (ASAP), recommended efficiency level (also referred to as ''EL'') 3 for all design lines (also referred to as ''DLs''). The National Electrical Manufacturers Association (NEMA) and AK Steel recommended EL 1 for all DLs except for DL 2, for which no change from the current standard was recommended. Edison Electric Institute (EEI) and ATI Allegheny Ludlum recommended EL1 for DLs 1, 3, and 4 and no change from the current standard or a proposed standard of less than EL 1 for DLs 2 and 5. Therefore, the subcommittee did not arrive at consensus regarding proposed standard levels for medium-voltage liquid-immersed distribution transformers.

For medium-voltage dry-type distribution transformers, the subcommittee arrived at consensus and recommended a proposed standard of EL2 for DLs 11 and 12, from which the proposed standards for DLs 9, 10, 13A, 13B would be scaled. Transcripts of the subcommittee meetings and all data and materials presented at the subcommittee meetings are available at the DOE Web site at: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html*.

The ERAC subcommittee held meetings on September 28, 2011, October 13–14, 2011, November 9, 2011, and December 1–2, 2011, for low-voltage distribution transformers. The ERAC subcommittee also held webinars on November 21, 2011, and December 20, 2011. During the course of the September 28, 2011, meeting, the subcommittee agreed to its rules of procedure, finalized the schedule of the remaining meetings, and defined the procedural meaning of consensus. The subcommittee defined consensus as unanimous agreement from all present subcommittee members. Subcommittee members were allowed to abstain from voting for an efficiency level; their votes counted neither toward nor against the consensus.

The ERAC subcommittee for low-voltage distribution transformers consisted of representatives of parties having a defined stake in the outcome of the proposed standards.

- AK Steel Corporation
- American Council for an Energy-Efficient Economy
- Appliance Standards Awareness Project
- ATI-Allegheny Ludlum
- EarthJustice
- Eaton Corporation
- Federal Pacific Company
- Lakeview Metals
- Efficiency and Renewables Advisory Committee member
- Metglas, Inc.
- National Electrical Manufacturers Association
- Natural Resources Defense Council
- ONYX Power
- Pacific Gas and Electric Company
- Schneider Electric
- U.S. Department of Energy

DOE presented its draft engineering, life-cycle cost and national impacts analysis and results. During the meetings of October 14, 2011, DOE presented its revised analysis and heard from subcommittee members on various topics. During the meetings of November 9, 2011, DOE presented its revised analysis. During the meetings of December 1, 2011, DOE presented its revised analysis based on 2011 core-material prices.

At the conclusion of the final meeting, subcommittee members presented their energy efficiency level recommendations. For low-voltage dry-type distribution transformers, the advocates, represented by ASAP, recommended EL4 for all DLs, NEMA recommended EL 2 for DLs 7 and 8, and no change from the current standard for DL 6. EEI, AK Steel and ATI Allegheny Ludlum recommended EL 1 for DLs 7 and 8, and no change from the current standard for DL 6. The subcommittee did not arrive at consensus regarding a proposed standard for low-voltage dry-type distribution transformers. Transcripts of the subcommittee meetings and all data and materials presented at the subcommittee meetings are available at the DOE Web site at: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html*.

III. General Discussion

A. Test Procedures

Section 7(c) of the Process Rule [15] indicates that DOE will issue a final test procedure, if one is needed, prior to issuing a proposed rule for energy conservation standards. DOE published its test procedure for distribution transformers in the **Federal Register** as a final rule on April 27, 2006. 71 FR 24972.

1. General

Currently, DOE requires distribution transformers to comply with standards with their windings in the configuration that produces the greatest losses. (10 CFR 431, Subpart K, Appendix A) During the April 5, 2011, public meeting, DOE addressed issues and solicited comments about amending the energy conservation standards for distribution transformers, the analytical framework and results of its preliminary analysis, and potential energy efficiency standards. At the outset, DOE proposed to amend the test procedure under appendix A to subpart K of 10 CFR part 431, Uniform Test Method for Measuring the Energy Consumption of Distribution Transformers. DOE proposed to allow compliance testing in any secondary configuration and at the lowest basic impulse level (BIL) rating and to require compliance at the lowest BIL at which dual or multiple voltage distribution transformers are rated to operate.

The Northwest Power and Conservation Council (NPCC) and Northwest Energy Efficiency Alliance (NEEA) [16] jointly submitted comments that the test procedure should adhere to specifications that do not make it difficult for the most challenging designs to comply with the standard, or else these transformer designs may be eliminated from the marketplace. (NPCC/NEEA, No. 11 at p. 2) [17] NPCC and NEEA further noted that they would support a change to allow manufacturers to test at a single voltage for models with a range of voltage taps that is ± 5 percent, using the middle voltage of that range. (NPCC/NEEA, No. 11 at p. 3) Finally, NPCC and NEEA requested that DOE explicitly explain the benefit of any changes to the test procedure, since certain changes could make future and past ratings more difficult to consistently compare. (NPCC/NEEA, No. 11 at p. 3)

NEMA commented that distribution transformers are rated to operate at multiple kilovolt ampere (kVA) ratings corresponding to passive cooling, active cooling, or a combination of both. NEMA stated that the regulation should clarify that transformers with multiple kVA ratings should comply at the base rating (passive cooling). (NEMA, No. 13 at pp. 2–3)

Although DOE does not intend to eliminate features offering unique utility from the marketplace, it wishes to gather more information on the specific efficiency differences between winding configurations as well as the relative frequencies of their uses. With this in mind and considering the comments, DOE proposes to continue requiring compliance testing in the primary and secondary winding configuration with the highest losses, as is currently required under appendix A to subpart K of 10 CFR part 431. DOE agrees that passive cooling is the most common

[15] The Process Rule provides guidance on how DOE conducts its energy conservation standards rulemakings, including the analytical steps and sequencing of rulemaking stages (such as test procedures and energy conservation standards). (10 CFR part 430, Subpart C, Appendix A).

[16] The Northwest Power and Conservation Council (NPCC) and Northwest Energy Efficiency Alliance (NEEA) submitted joint comments and are hereinafter referred to as NPCC/NEEA.

[17] This short-hand citation format is used throughout this document. For example: ''(NPCC/NEEA, No. 11 at p. 2)'' refers to a (1) a joint statement that was submitted by NPCC and NEEA and is recorded at *http://www.regulations.gov/#!home* in the docket under ''Energy Conservation Standards for Distribution Transformers,'' Docket Number EERE–2010–BT–STD–0048, as comment number 11; and (2) a passage that appears on page 2 of that statement.

mode of operation for distribution transformers employed in power distribution and clarifies that manufacturers are only required to demonstrate compliance at kVA ratings that correspond to passive cooling.[18]

DOE requests comment and corroborating data on how often distribution transformers are operated with their primary and secondary windings in different configurations, and on the magnitude of the additional losses in less efficient configurations.

2. Multiple kVA Ratings

Currently, DOE is nonspecific on which kVA rating should be used to assess compliance in the case of distribution transformers with more than one kVA.

ABB's recommendations on transformers with multiple kVA ratings depended on how the transformer was cooled. For naturally-cooled transformers, ABB recommended that they should be required to meet the efficiency standard for every kVA rating. However, ABB suggested that forced-cooled transformers should only have to meet the efficiency standard at the naturally-cooled kVA rating. This is because the forced-cooled rating, which is meant only for temporary overload conditions, is dependent on the operation of auxiliary cooling fans that have a lower operating life than the transformer. (ABB, No. 14 at pp. 3–5)

DOE has received nearly unanimous feedback that transformers in distribution applications are seldom designed to rely on active cooling even occasionally and that the majority of designs lack active cooling altogether. DOE wishes to clarify that manufacturers are only required to demonstrate compliance at kVA ratings that correspond to passive cooling.

3. Dual/Multiple-Voltage Basic Impulse Level

Currently, DOE requires distribution transformers to comply with standards using the BIL rating of the winding configuration that produces the greatest losses. (10 CFR 431, Subpart K, Appendix A)

Several stakeholders commented that distribution transformers with multiple BIL ratings should comply with the efficiency based on the highest BIL rating, as the transformer core is based on the highest BIL rating. (Hammond (HPS), No. 3 at p. 1; NEMA, No. 13 at p. 2; and FPT, No. 27 at p. 13) NEMA noted that for dual/multiple distribution transformers with varying BIL levels, DOE should align its requirements with those of the Institute of Electrical and Electronics Engineers (IEEE) standards (C57.12.00 for liquid-filled, NEMA ST20–1992:3.3 for low-voltage) and require testing in the ''as shipped'' condition, which would base the efficiency on the highest BIL rating, matching IEEE and industry practice. (NEMA, No. 13 at p. 2) Federal Pacific Transformers (FPT) stated that medium-voltage distribution transformers with multiple configurations should be held to the efficiency standard of the configuration with the highest BIL rating because the distribution transformer is required to be much larger for the higher BIL rating and, therefore, cannot reasonably meet the energy efficiency level of the lower BIL rating. (FPT, No. 27 at p. 13) FPT also expressed their support for testing on the highest BIL efficiency rating for re-connectable distribution transformers. (FPT, Pub. Mtg. Tr., No. 34 at p. 40)[19]

ABB commented that DOE should not change the test requirement to allow compliance at the lowest BIL rating. According to ABB, there is no way to ascertain which operating condition a distribution transformer will use over its lifetime. ABB stated that DOE should require that the efficiency be met on any operational configuration for which the distribution transformer is designed for continuous operation. (ABB, No. 14 at p. 2)

DOE needs to gather more information in order to be certain that allowing compliance at any BIL rating would not result in lowered energy savings relative to what is predicted by DOE's analysis. DOE proposes to maintain the current requirement to comply in the configuration that gives rise to the greatest losses.

4. Dual/Multiple-Voltage Primary Windings

Currently, DOE requires manufacturers to comply with energy conservation standards with distribution transformer primary windings (''primaries'') in the configuration that produces the highest losses. (10 CFR 431, Subpart K, Appendix A)

Where DOE invited additional comments about the test procedures, Howard Industries added that, under the presumption that DOE would allow compliance testing in any of the secondary configurations (''secondaries''), DOE should insert the word ''primary'' into the testing requirements [at section 5.0, Determining the Efficiency Value of the Transformer, under appendix A to subpart K of 10 CFR part 431], and require the manufacturer to ''determine the basic model's efficiency at the 'primary' voltage at which the highest losses occur or at each 'primary' voltage at which the distribution transformer is rated to operate.'' Howard Industries noted that, for multiple-voltage distribution transformers, this insertion would clarify that distribution transformer efficiency is determined by the primary voltage and that the low-voltage or secondary winding configuration that is used would be at the manufacturer's discretion. (HI, No. 23 at p. 2)

HVOLT commented that distribution transformers with dual or multiple-voltage primary windings should be allowed to comply while the primaries are connected in series. HVOLT explained that utilities purchase these transformers to upgrade a distribution circuit to higher voltages within a few years of purchase and that these transformers will spend more than 90 percent of their lives with the primary windings connected in series. (HVOLT, No. 33 at p. 2)

DOE understands that, in contrast to the secondary windings, reconfigurable primaries typically exhibit a larger variation in efficiency between series and primary connections. As the above commenters have pointed out, however, such transformers are often purchased with the intent of upgrading the local power grid to a higher operating voltage with lowered overall system losses. In that sense, transformers with reconfigurable primaries can be seen as a stepping stone toward greater overall energy savings, even if those savings do not occur within the transformer itself.

DOE conducted several sensitivity analyses to examine the effects of a reconfigurable primary winding on efficiency and found that the difference between the efficiency of the secondary and the efficiency of the primary was more significant than in the case of configurable secondary windings.

DOE wishes to obtain more information on both the difference in losses between different winding configurations as well as the different configurations' relative frequency of operation in practice. DOE requests comment on this proposal to continue to mandate compliance in the highest-loss configuration and data illustrating the

[18] Passive cooling is cooling that does not require fans, pumps, or other energy-consuming means of increasing thermal convection.

[19] This short-hand citation format for the public meeting transcript is used throughout this document. For example: ''(FPT, Pub. Mtg. Tr., No. 34 at p. 40)'' refers to a comment on the page number of the transcript of the ''Public Meeting on Energy Conservation Standard Preliminary Analysis for Distribution Transformers,'' held in Washington, DC, April 5, 2011.

efficiency differences between primary winding configurations.

5. Dual/Multiple-Voltage Secondary Windings

Currently, DOE requires transformers to comply with their secondary windings in the configuration that produces the greatest losses. (10 CFR 431, Subpart K, Appendix A)

Interested parties commented that DOE should not change the current test requirement to permit compliance testing in any secondary configuration at the lowest BIL rating for transformers with dual/multiple-voltage secondary windings, and that these transformers should comply with an energy efficiency level using the combination of connections that produces the highest losses. (HPS, No. 3 at p.1; NPCC/NEEA, No. 11 at p. 3; and ABB, No. 14 at p. 2) ABB also noted that there is no way to determine the connection on which a unit will be operated over its lifetime.

Schneider Electric (SE) commented that NEMA ST20–1992: 3.3 [Dry-Type Transformers for General Applications, NEMA ST 20–1992(R1997)] requires that ''low-voltage [transformers] be shipped with the connections done for the highest voltage'' and requested that ''all compliance testing be done in the configuration requirement of ST–20.'' (SE., No. 18 at p. 5) Similarly, NEMA commented that ''DOE should align its requirements with those of IEEE standards (C57.12.00 for liquid-filled, NEMA ST 20–1992: 3.3 for low-voltage), requiring testing in the 'as shipped' condition.'' (NEMA, No. 13 at p. 2) Further, NEMA noted that industry practice is to ship these units in the series connection. Similarly, FPT asserted that, ''for units with multiple (series-parallel) low-voltage ratings, the efficiency standard should be based on the highest voltage (series) connection, which matches the IEEE standard and industry practice.'' (FPT, No. 27 at p. 11)

Several interested parties expressed support for DOE's proposal to allow compliance testing in any secondary configuration at the lowest voltage rating. (Power Partners, Inc. (PP), Pub. Mtg. Tr., No. 34 at p. 40; HVOLT, No. 33 at p. 2; HI, No. 23 at p.2; and PP, No. 19 at p. 2) HVOLT noted that about 99 percent of dual/multiple-voltage single-phase, pole-type transformers are used in the series connection, and the work to otherwise reconnect to the secondary is burdensome. (HVOLT, No. 33 at p.2) Similarly, HI pointed out that very few transformers are ever reconnected for parallel operation and that testing requirements in a parallel configuration can be burdensome. (HI, No. 23 at p. 2)

Furthermore, HVOLT commented that a distribution transformer that is designed for a dual voltage rating does not have an even multiple quantity of series connections compared to parallel connection designs. This means that there are already unused windings that will be in the parallel connection. Because the testing procedure requires that they be tested on the lowest BIL connections, these types of distribution transformers effectively have a higher efficiency requirement. HVOLT believes dual voltage distribution transformers are being unduly burdened by the test procedure. (HVOLT, Pub. Mtg. Tr., No. 34 at pp. 38–39)

HI recommended that DOE adjust the efficiency value by 0.1 for dual/multiple-voltage liquid-immersed distribution transformers with windings having a ratio other than 2:1, due to the complexity of the winding for these distribution transformers. HI noted that a similar approach was taken by the Canadian Standards Associations Standards. (HI, No. 23 at p. 2)

DOE understands that some distribution transformers may be shipped with reconfigurable secondary windings, and that certain configurations may have different efficiencies. Currently, DOE requires distribution transformers to be tested in the configuration that exhibits the highest losses, which is usually with the secondary windings in parallel. Whereas the IEEE Standard [20] requires a distribution transformer to be shipped with the windings in series, a manufacturer testing for compliance could need to test the distribution transformer for energy efficiency, disassemble the unit, reconfigure the windings, and reassemble the unit for shipping at added time and expense. Nonetheless, DOE would need to obtain more specific information on the potential net energy losses associated with permitting distribution transformers to be tested in any secondary winding configuration and proposes to maintain the current requirement of compliance in the configuration that produces the greatest losses.

DOE requests comment on secondary winding configurations, and on the magnitude of the additional losses associated with the less efficient configurations as well as the relative frequencies of operation in each winding configuration.

6. Loading

Currently, DOE requires that both liquid-immersed and medium-voltage, dry-type distribution transformers comply with standards at 50 percent loading and that low-voltage, dry-type distribution transformers comply at 35 percent loading.

Warner Power (WP) commented that a single 35 percent test load for low-voltage dry-type distribution transformers (LVDTs) does not adequately reflect known service conditions at widely varying, and often low, average loads. It cited several studies indicating a lower average load factor and a shrinking load factor and recommended LVDTs be certified at 15 percent and 35 percent loading. (WP, No. 30 at pp. 1–2) In addition, Warner Power suggested that a weighted curve between 10 percent and 80 percent load factors would be better than a single 35 percent load factor. It recommended using published data to more accurately reflect real load conditions, accounting for daily, weekly, and seasonal variations. For LVDT transformers, it pointed out that the load profile should characterize the typical use in different types of buildings. (WP, No. 30 at p.5) NPCC and NEEA opined that, with better loading data for distribution transformers, they would support testing at multiple loading points, such as 15, 35, 50 and 70 percent, with a weighted-average calculation that is unique to each class. They noted, however, that such data is likely not available. (NPCC/NEEA, No. 11 at pp. 2–3)

HVOLT commented that the test procedure-required load values for all three categories of distribution transformers appeared reasonable for the foreseeable future. Otherwise, with electric vehicles and plug-in hybrids entering the market, HVOLT opined that root-mean-square loading will increase in the long-term but may take decades to have an effect. (HVOLT, No. 33 at p. 1) NPCC and NEEA announced that they are collecting additional field data to inform the appropriateness of the test procedure loading points. (NPCC/NEEA, No. 11 at p. 2)

NEMA, ABB, and Schneider Electric (SE) all commented that DOE should not modify its test procedures by considering weighted-average loadings for core deactivation efficiency standards. (NEMA, No. 13 at p. 2; ABB, No. 14 at pp. 2–3; and SE., Pub. Mtg. Tr., No. 34 at p. 57) ABB further clarified that this approach would be inaccurate because the true load varies by every distinct installation. Instead, it asserted that the current load factors are more appropriate because they reflect the aggregate impact on the national grid. (ABB, No. 14 at pp. 2–3)

[20] IEEE C57.12.00.

NPCC and NEEA recommended that DOE attempt to gather data on actual core deactivation designs and control algorithms before it changes the test procedure. Additionally, NPCC and NEEA suggested that DOE gather data on the performance of distribution transformers under various load conditions. If this data is unavailable or inconclusive, they suggested that DOE not change the test procedure at this time but rather ensure that core deactivation technology is examined in the next rulemaking for distribution transformers. (NPCC/NEEA, No. 11 at p. 3)

Warner Power (WP) indicated its intent to submit data concerning modified test procedures which would better capture core deactivation technologies. (WP, Pub. Mtg. Tr., No. 34 at p. 42)

DOE is proposing to maintain the use of a single, discrete loading point for distribution transformers because the use of weighted-average loadings would represent a fairly significant change in the test procedure, possibly causing some units that meet energy conservation standards to no longer do so. In the future, DOE may consider modifying this approach. DOE welcomes relevant data in conjunction with comments on typical distribution transformer loading profiles.

B. Technological Feasibility

1. General

There are distribution transformers available at all of the energy efficiency levels considered in today's notice of proposed rulemaking. Therefore, DOE believes all of the energy efficiency levels adopted by today's notice of proposed rulemaking are technologically feasible.

2. Maximum Technologically Feasible Levels

When DOE proposes to adopt, or decline to adopt, an amended or new standard for a type of covered product, section 325(o)(2) of EPCA, 42 U.S.C. 6295(o)(2), requires that DOE determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible. While developing the energy conservation standards for liquid-immersed and medium-voltage, dry-type distribution transformers that were codified under 10 CFR 431.196, DOE determined the maximum technologically feasible (''max-tech'') energy efficiency level through its engineering analysis using the most efficient materials, such as core steels and winding materials, and applied design parameters that drove distribution transformer software to create designs at the highest efficiencies achievable at the time. 71 FR 44362 (August 4, 2006) and 72 FR 58196 (October 12, 2007). DOE used these designs to establish max-tech levels for its LCC analysis and scaled them to other kVA ratings within a given design line, thereby establishing max-tech efficiencies for all the distribution transformer kVA ratings.

C. Energy Savings

1. Determination of Savings

Section 325(o)(2)(A) of EPCA, 42 U.S.C. 6295(o)(2)(A), requires that any new or amended standard must be chosen so as to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. In determining whether economic justification exists, key factors include the total projected amount of energy savings likely to result directly from the standard and the savings in operating costs throughout the estimated average life of the covered equipment. To understand the national economic impact of potential efficiency regulations for distribution transformers, DOE conducted a national impact analysis (NIA) using a spreadsheet model to estimate future national energy savings (NES) from amended energy conservation standards.[21] For each TSL, DOE forecasted energy savings beginning in 2016, the year that manufacturers would be required to comply with amended standards, and ending in 2045. DOE quantified the energy savings for each TSL as the difference in energy consumption between the ''standards case'' and the ''base case.'' The base case represents the forecast of energy consumption in the absence of amended mandatory efficiency standards, and takes into consideration market demand for more-efficient equipment.

The NIA spreadsheet model calculates the electricity savings in ''site energy'' expressed in kilowatt-hours (kWh). Site energy is the energy directly consumed by distribution transformer products at the locations where they are used. DOE reports national energy savings on an annual basis in terms of the aggregated source (primary) energy savings, which is the savings in the energy that is used to generate and transmit the site energy. (See TSD chapter 10.) To convert site energy to source energy, DOE derived annual conversion factors from the model used to prepare the Energy Information Administration's (EIA) *Annual Energy Outlook 2011 (AEO2011).*

[21] The NIA spreadsheet model is described in section IV.G of this notice.

2. Significance of Savings

As noted above, 42 U.S.C. 6295(o)(3)(B) prevents DOE from adopting a standard for covered equipment if such a standard would not result in ''significant'' energy savings. While EPCA does not define the term ''significant,'' the U.S. Court of Appeals for the District of Columbia, in *Natural Resources Defense Council* v. *Herrington,* 768 F.2d 1355, 1373 (D.C. Cir. 1985), indicated that Congress intended ''significant'' energy savings in this context to be savings that were not ''genuinely trivial.'' The energy savings for all of the TSLs considered in this rulemaking are non-trivial and, therefore, DOE considers them ''significant'' within the meaning of EPCA section 325(o).

D. Economic Justification

1. Specific Criteria

As noted previously, EPCA requires DOE to evaluate seven factors to determine whether a potential energy conservation standard is economically justified. (42 U.S.C. 6295(o)(2)(B)(i)) The following sections describe how DOE has addressed each of the seven factors in this rulemaking.

a. Economic Impact on Manufacturers and Consumers

In determining the impacts of an amended standard on manufacturers, DOE first determines the quantitative impacts using an annual cash-flow approach. This includes both a short-term assessment, based on the cost and capital requirements during the period between the issuance of a regulation and when entities must comply with the regulation, and a long-term assessment over a 30-year analysis period. The industry-wide impacts analyzed include INPV (which values the industry on the basis of expected future cash flows), cash flows by year, changes in revenue and income, and other measures of impact, as appropriate. Second, DOE analyzes and reports the impacts on different types of manufacturers, paying particular attention to impacts on small manufacturers. Third, DOE considers the impact of standards on domestic manufacturer employment and manufacturing capacity, as well as the potential for standards to result in plant closures and loss of capital investment. Finally, DOE takes into account cumulative impacts of different DOE regulations and other regulatory requirements on manufacturers.

For individual consumers, measures of economic impact include the changes in LCC and the PBP associated with new or amended standards. The LCC, which is separately specified in EPCA as one of the seven factors to be considered in determining the economic justification for a new or amended standard (42 U.S.C. 6295(o)(2)(B)(i)(II)), is discussed in the following section. For consumers in the aggregate, DOE also calculates the national net present value of the economic impacts on consumers over the forecast period used in a particular rulemaking.

Federal Pacific suggested that DOE establish reference efficiencies by rating, as defined by NEMA Premium, for those users who want efficiencies higher than current minimum efficiencies. However, they did not want these reference efficiencies to become the new minimum efficiency mandates. (FPT, No. 27 at p. 2)

The National Rural Electric Cooperative Association (NRECA) recommended that DOE not raise the efficiency standards for the liquid-filled distribution transformers, since many rural utilities with low distribution transformer loads cannot economically justify the current energy efficiency level. (NRECA, No. 31 and 36 at p. 1)

DOE appreciates the comments and considers impacts to consumers, manufacturers, and utilities in TSD chapters 8, 12, and 14, respectively. DOE welcomes comment on these analyses and on any subset of consumers, manufacturers, or utilities that could be disproportionately affected.

b. Life-Cycle Costs

The LCC is the sum of the purchase price of a type of equipment (including its installation) and the operating expense (including energy and maintenance and repair expenditures) discounted over the lifetime of the product. The LCC savings for the considered energy efficiency levels are calculated relative to a base case that reflects likely trends in the absence of amended standards. The LCC analysis requires a variety of inputs, such as equipment prices, equipment energy consumption, energy prices, maintenance and repair costs, equipment lifetime, and consumer discount rates. DOE assumed in its analysis that consumers will purchase the considered equipment in 2016.

To account for uncertainty and variability in specific inputs, such as product lifetime and discount rate, DOE uses a distribution of values with probabilities attached to each value. A distinct advantage of this approach is that DOE can identify the percentage of consumers estimated to receive LCC savings or experience an LCC increase, in addition to the average LCC savings associated with a particular standard level. In addition to identifying ranges of impacts, DOE evaluates the LCC impacts of potential standards on identifiable subgroups of consumers that may be disproportionately affected by a national standard.

c. Energy Savings

While significant conservation of energy is a separate statutory requirement for imposing an energy conservation standard, EPCA requires DOE, in determining the economic justification of a standard, to consider the total projected energy savings that are expected to result directly from the standard. (42 U.S.C. 6295(o)(2)(B)(i)(III)) DOE uses the NIA spreadsheet results in its consideration of total projected energy savings.

d. Lessening of Utility or Performance of Products

In establishing classes of products, and in evaluating design options and the impact of potential standard levels, DOE sought to develop standards for distribution transformers that would not lessen the utility or performance of these products. (42 U.S.C. 6295(o)(2)(B)(i)(IV)) None of the TSLs presented in today's NOPR would substantially reduce the utility or performance of the equipment under consideration in the rulemaking.

DOE requests comment on the possibility of reduced equipment performance or utility resulting from today's proposed standards, particularly the risk of reducing the ability to perform periodic maintenance and the risk of increasing vibration and acoustic noise.

e. Impact of Any Lessening of Competition

EPCA directs DOE to consider any lessening of competition that is likely to result from standards. It also directs the Attorney General of the United States (Attorney General) to determine the impact, if any, of any lessening of competition likely to result from a proposed standard and to transmit such determination to the Secretary within 60 days of the publication of a proposed rule, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii)) DOE will transmit a copy of today's proposed rule to the Attorney General with a request that the Department of Justice (DOJ) provide its determination on this issue. DOE will address the Attorney General's determination in the final rule.

f. Need for National Energy Conservation

Certain benefits of the proposed standards are likely to be reflected in improvements to the security and reliability of the Nation's energy system. Reductions in the demand for electricity may also result in reduced costs for maintaining the reliability of the Nation's electricity system. DOE conducts a utility impact analysis to estimate how standards may affect the Nation's needed power generation capacity. (See 42 U.S.C. 6295(o)(2)(B)(i)(VI))

Energy savings from the proposed standards are also likely to result in environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases associated with energy production. DOE reports the environmental effects from the proposed standards, and from each TSL it considered, in the environmental assessment contained in chapter 15 in the NOPR TSD. DOE also reports estimates of the economic value of emissions reductions resulting from the considered TSLs.

g. Other Factors

EPCA allows the Secretary of Energy, in determining whether a standard is economically justified, to consider any other factors that the Secretary considers relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VII)) In developing the proposals of this notice, DOE has also considered the matter of electrical steel availability. This factor is discussed further in section V.B.8.

2. Rebuttable Presumption

As set forth in 42 U.S.C. 6295(o)(2)(B)(iii), EPCA creates a rebuttable presumption that an energy conservation standard is economically justified if the additional cost to the consumer of a product that meets the standard is less than three times the value of the first-year of energy savings resulting from the standard, as calculated under the applicable DOE test procedure. DOE's LCC and payback period (PBP) analyses generate values used to calculate the PBP for consumers of potential amended energy conservation standards. These analyses include, but are not limited to, the three-year PBP contemplated under the rebuttable presumption test. However, DOE routinely conducts an economic analysis that considers the full range of impacts to the consumer, manufacturer, Nation, and environment, as required under 42 U.S.C. 6295(o)(2)(B)(i). The results of this analysis serve as the basis for DOE to definitively evaluate the economic justification for a potential standard level (thereby supporting or rebutting the results of any preliminary determination of economic justification). The rebuttable presumption payback calculation is discussed in section V.B.1.c of this NOPR and chapter 8 of the NOPR TSD.

IV. Methodology and Discussion of Related Comments

DOE used two spreadsheet tools to estimate the impact of today's proposed standards. The first spreadsheet calculates LCCs and PBPs of potential new energy conservation standards. The second provides shipments forecasts and calculates national energy savings and net present value impacts of potential new energy conservation standards. DOE also assessed manufacturer impacts, largely through use of the Government Regulatory Impact Model (GRIM). The two spreadsheets are available online at the rulemaking Web site: *http://www1.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html*.

Additionally, DOE estimated the impacts of energy conservation standards for distribution transformers on utilities and the environment. DOE used a version of EIA's National Energy Modeling System (NEMS) for the utility and environmental analyses. The NEMS model simulates the energy sector of the U.S. economy. EIA uses NEMS to prepare its *Annual Energy Outlook (AEO),* a widely known energy forecast for the United States. The version of NEMS used for appliance standards analysis is called NEMS–BT [22] and is based on the *AEO* version with minor modifications.[23] The NEMS–BT offers a sophisticated picture of the effect of standards because it accounts for the interactions between the various energy supply and demand sectors and the economy as a whole.

A. Market and Technology Assessment

For the market and technology assessment, DOE develops information that provides an overall picture of the market for the products concerned, including the purpose of the products, the industry structure, and market characteristics. This activity includes both quantitative and qualitative assessments, based primarily on publicly available information. The subjects addressed in the market and technology assessment for this rulemaking include scope of coverage, definitions, equipment classes, types of products sold and offered for sale, and technology options that could improve the energy efficiency of the products under examination. Chapter 3 of the TSD contains additional discussion of the market and technology assessment.

1. Scope of Coverage

This section addresses the scope of coverage for today's proposal, stating which products would be subject to amended standards. The numerous comments DOE received on the scope of today's proposal are also summarized and addressed in this section.

a. Definitions

Today's proposed standards rulemaking concerns distribution transformers, which include three categories: liquid-immersed, low-voltage dry-type (LVDT) and medium-voltage dry-type (MVDT). The definition of a distribution transformer was presented in EPACT 2005 and then further refined by DOE when it was codified into 10 CFR 431.192 by the April 27, 2006 final rule for distribution transformer test procedures (71 FR 24995) as follows:

Distribution transformer means a transformer that—

(1) Has an input voltage of 34.5 kV or less;

(2) Has an output voltage of 600 V or less;

(3) Is rated for operation at a frequency of 60 Hz; and

(4) Has a capacity of 10 kVA to 2500 kVA for liquid-immersed units and 15 kVA to 2500 kVA for dry-type units; but

(5) The term ''distribution transformer'' does not include a transformer that is an—

(i) Autotransformer;

(ii) Drive (isolation) transformer;

(iii) Grounding transformer;

(iv) Machine-tool (control) transformer;

(v) Non-ventilated transformer;

(vi) Rectifier transformer;

(vii) Regulating transformer;

(viii) Sealed transformer;

(ix) Special-impedance transformer;

(x) Testing transformer;

(xi) Transformer with tap range of 20 percent or more;

(xii) Uninterruptible power supply transformer; or

(xiii) Welding transformer.

Additional detail on the definitions of each of these excluded transformers can found in TSD chapter 3.

DOE received multiple comments seeking clarification on various terms used in the definition of a distribution transformer. NEMA requested that DOE amend the definitions of two transformer types explicitly excluded from the distribution transformer definition, namely ''rectifier transformer'' and ''testing transformer.'' NEMA suggested that both definitions should require the nameplates of such transformers to identify the transformers as being for such uses only. (NEMA, No. 13 at p. 10) Furthermore, NEMA recommended that transformers used inside underground tunneling equipment should be added to the definition for underground mining distribution transformers because this equipment is specialized and requires a compact transformer. (NEMA, No. 13 at p. 10) FPT agreed with NEMA and recommended that DOE amend the definition of ''underground mining transformer'' with the following sentence: ''The term 'mining' may also be understood to mean underground tunneling or digging.'' FPT added that the term ''mining'' should be clarified to encompass any underground operation involving the removal of material underground, such as digging or tunneling, which have the same restrictions with the size of distribution transformers, but might not be considered to be mining applications. (FPT, No. 27 at pp. 10–11) Finally, PP commented that DOE should clarify the definitions of input and output voltage to reflect the three-phase system voltages and not the line to ground voltage, which is typically the input voltage for single-phase transformers. (PP, No. 1 at p. 1)

DOE agrees that these additions to the definitions of ''rectifier transformer'' and ''testing transformer'' are helpful in aiding the consumer to distinguish rectifier and testing transformers and therefore proposes to amend its definitions correspondingly. Additionally, DOE believes that transformers used for the removal of material underground are subject to similar space constraints as traditional mining transformers and therefore their ability to meet higher efficiency standards are similarly restricted. However, DOE wishes to learn more about the nature of those applications in order to define the units precisely. Consequently, DOE proposes to maintain the current definition of ''mining transformer'' unless it is able to determine that the expansion, as

[22] BT stands for DOE's Building Technologies Program.

[23] The EIA allows the use of the name ''NEMS'' to describe only an AEO version of the model without any modification to code or data. Because the present analysis entails some minor code modifications and runs the model under various policy scenarios that deviate from AEO assumptions, the name ''NEMS–BT'' refers to the model as used here. For more information on NEMS, refer to The National Energy Modeling System: An Overview, DOE/EIA–0581 (98) (Feb.1998), available at: *http://tonto.eia.doe.gov/FTPROOT/forecasting/058198.pdf.*

suggested by NEMA and FPT, is warranted and able to be implemented with sufficient specificity. DOE requests comment on that proposal and any information useful in understanding how transformers used in certain underground applications differ and could be defined precisely. Finally, DOE also wishes to remove any ambiguity in the terms ''input voltage'' and ''output voltage'' and requests comment on where that ambiguity lies.

Multiple interested parties submitted comments regarding the kVA ratings that are currently included in the scope of coverage. PP commented that DOE should consider removing single-phase liquid-immersed distribution transformers rated above 250 kVA with a low-voltage rating of 600V from the scope of the regulation. They contended that these transformers constitute a very low volume of shipments (481 units in 2009) and MVA capacity shipped (201 MVA in 2009) and therefore the overall national energy savings would not be significant. (PP, No. 19 at pp. 1–3; Pub. Mtg. Tr., No. 34 at p. 34) PP added that the impact of increased weight and dimensions is greater in these sizes where maximum tank size and weight constraints are critical. Moreover, PP proposed that DOE should consider 500 kVA the upper limit of kVA ratings covered and shift the lower limit from 10 to 5 kVA. (PP, Pub. Mtg. Tr., No. 34 at pp. 46, 73–74; PP, No. 19 at pp. 1–2) Similarly, NPCC and NEEA urged DOE to decide whether to include single-phase liquid-immersed distribution transformers down to 5 kVA in the scope of coverage. (NPCC/NEEA, No. 11 at p. 9)

BBF and Associates suggested that DOE investigate increasing the scope of the rulemaking to include transformers from 2500 kVA to 20 MVA. (BBF, Pub. Mtg. Tr., No. 34 at p. 279) CDA recommended that DOE include transformers up to 30,000 kVA (30 MVA) in its scope, including sub-station transformers. It noted that these units are within the distribution system, and are substantial in unit shipment volumes. (CDA, No. 17 at pp. 1–2, 4)

DOE understands that larger (250–833 kVA) single-phase, liquid-immersed units are currently covered and is not proposing to exclude them from consideration for this rulemaking. Because these ratings were covered by the previous rulemaking for distribution transformers, DOE is statutorily prohibited from backsliding and excluding such products from regulation at this time. (See 42 U.S.C. 6295(o)(1)6316(a)) However, DOE notes that it is accounting for the added life-cycle costs of larger and heavier transformers and discusses its methodology for this in chapter 6 of the TSD. Additionally, DOE determined during the previous standards rulemaking that 5 kVA transformers were below the kVA limit ''commonly understood to be distribution transformers.'' 69 FR 45381. DOE proposes to maintain that stance for this rulemaking as these units are generally too small to be employed in power distribution and collectively consume extremely little power. Similarly, units larger than 2.5 MVA (DOE's current upper limit) are usually considered substation transformers, which DOE is not proposing to cover. DOE invites comment on its proposal to maintain the current scope of coverage.

Interested parties also solicited clarification from DOE on transformers that are used in a variety of applications. FPT requested that DOE clarify whether existing efficiency standards apply to transformers used in aircraft, trains/locomotives, offshore drilling platforms, mobile substations, ships, and other similar applications. (FPT, No. 27 at p. 2) Furthermore, FPT recommended that DOE investigate whether transformers being used in wind farms or solar energy applications should be exempted since these designs should be optimized at higher loading levels than the test procedure loading points of 35 percent (low-voltage dry-type) and 50 percent (liquid-immersed and medium-voltage dry-type). (FPT, No. 27 at p. 2) Lastly, CDA commented that DOE should expand the scope of the rulemaking to include step-up transformers of kVA sizes that are currently included in the scope, such as transformers used in wind farms. (CDA, No. 17 at pp. 2–3)

EPACT 2005 defined the term ''distribution transformer,'' 42 U.S.C. 6291(35)(B)(ii), to mean a transformer that (i) has an input voltage of 34.5 kilovolts or less; (ii) has an output voltage of 600 volts or less; and (iii) is rated for operation at a frequency of 60 Hertz. The definition goes on to generally exclude certain specialized-application distribution transformers. At this time, DOE is not proposing to cover distribution transformers used in mobile applications because they do not represent traditional power distribution. For example, aircraft and marine transformers frequently operate at 400 Hz, and mobile substation transformers often fall outside the currently defined voltage and kVA ranges. Furthermore, transformers used in mobile applications could be unduly impacted by any increases in size and weight required to reach higher efficiencies. DOE requests comment on the topic of transformers used in mobile applications and any data helpful in considering whether standards are warranted. DOE also requests comment on the likelihood of this exclusion serving as a loophole in the face of increasing standards.

DOE does not propose to exclude transformers used in renewable energy applications simply because of the potential difference in loading that they may experience. DOE currently understands that the users who buy transformers for those applications tend to value losses highly and that such transformers would have little trouble meeting standards. Furthermore, DOE notes that its choices for the test procedure loading points do not imply that it intends to exclusively cover transformers with precisely those loading values. Rather, DOE accounts for consumers purchasing transformers optimized for loading values other than the test procedure value in its LCC analysis.

DOE proposes to continue to not set standards for step-up transformers, because they are not ordinarily considered to be performing a power distribution function. However, DOE is aware that step-up transformers may be able to be used in place of step-down transformers and may represent a potential loophole as standards increase. DOE requests comment on its proposal to continue not to set standards for step-up transformers.

Finally, DOE received an inquiry with regards to how it plans to deal with core deactivation technology. Specifically, Schneider Electric wanted to know if DOE would change the definition of transformers to include banks of transformers. (SE., Pub. Mtg. Tr., No. 34 at p. 57) Core-deactivation technology employs a system of smaller transformers to replace a single, larger transformer. For example, using this technology, three transformers sized at 25 kVA and operated in parallel could replace a single 75 kVA transformer. The smaller transformers that compose the system can then be activated and deactivated using core deactivation technology based on the loading demand. At present, DOE is not proposing to set efficiency standards for banks of transformers, but notes that each constituent transformer would be subject to an efficiency standard if, on its own, it meets the definition of a distribution transformer.

b. Underground Mining Transformer Coverage

In the October 12, 2007, final rule on energy conservation standards for distributions transformers, DOE codified into 10 CFR 431.192 the definition of an ''underground mining distribution transformer'' as follows:

Underground mining distribution transformer means a medium-voltage dry-type distribution transformer that is built only for installation in an underground mine or inside equipment for use in an underground mine, and that has a nameplate which identifies the transformer as being for this use only. 72 FR 58239.

In that same final rule, DOE also clarified that although it believed these transformers were within its scope of coverage, it was not establishing any energy conservation standards for underground mining transformers. At the time, DOE recognized that these transformers were subject to unique and extreme dimensional constraints which impact their efficiency and performance capabilities. Therefore, DOE established a separate equipment class for mining transformers and stated that it may consider energy conservation standards for such transformers at a later date. Although DOE did not establish energy conservation standards for such transformers, it also did not add underground mining transformers to the list of excluded transformers in the definition of a distribution transformer. DOE retained that it had the authority to cover such equipment if, during a later analysis, it found technologically feasible and economically justified energy conservation standard levels. 72 FR 58197.

In response to the March 2, 2011 preliminary analysis, NEMA recommended that underground mining distribution transformers, including transformers used inside underground tunneling equipment, should be included on the exemption list to clarify that the standards shall not apply to them. (NEMA, No. 13 at p. 10) NPCC and NEEA commented that DOE should remove any confusion about the coverage of underground mining transformers either by setting standards for these units or adding them to the list of excluded transformers. (NPCC/NEEA, No. 11 at p. 9)

FPT urged DOE to exclude mining transformers from minimum efficiency levels because it would result in undue economic hardship for the mining industry and unrealistic design constraints on mining equipment that use such transformers. FPT pointed out that mining transformers make up a small portion of the market and that the total amount of energy they consume is very small compared to the national energy consumption rate. FPT also noted that a mining transformer is more specialized in its design and application than many of the transformers excluded from the definition of distribution transformers under 10 CFR 431.192. (FPT, No. 27 at pp. 8–10)

In view of the above, DOE understands that underground mining transformers are subject to a number of constraints that are not usually concerns for transformers used in general power distribution. Because space is critical in mines, an underground mining transformer may be at a considerable disadvantage in meeting an efficiency standard. Underground mining transformers are further disadvantaged by the fact that they must supply power at several output voltages simultaneously. For this rulemaking, DOE again proposes not to set standards for underground mining transformers, but recognizes the possibility of a loophole. Therefore, DOE continues to leave underground mining transformers off of the list of exempt distribution transformers and reserve a separate equipment class for mining transformers. DOE may set standards in the future if it believes that underground mining transformers are being purchased as a way to circumvent energy conservation standards.

c. Low-Voltage Dry-Type Distribution Transformers

10 CFR 431.192 defines the term ''low-voltage dry-type distribution transformer'' to be a distribution transformer that:

(1) Has an input voltage of 600 volts or less;

(2) Is air-cooled; and

(3) Does not use oil as a coolant.

Because EPACT 2005 prescribed standards for LVDTs, which DOE incorporated into its regulations at 70 FR 60407 (October 18, 2005) (codified at 10 CFR 431.196(a)), LVDTs were not included in the 2007 standards rulemaking. As a result, the settlement agreement following the publication of the 2007 final rule does not impact LVDT standards.

Two interested parties, EEI and SE., requested clarification on whether LVDT distribution transformers would be included in this rulemaking. (EEI, Public Mtg. Tr., No. 34 at p. 56, 27; SE., No. 7 at p. 1) In particular, SE questioned whether Congress would be involved in amending standards for LVDTs. (SE., No. 7 at p. 1) Further, SE expressed concern that there does not appear to be a timeline for the LVDT distribution transformer rulemaking and that one is needed in order to plan potential capital expenditures for any new efficiency levels. (SE., Pub. Mtg. Tr., No. 34 at p. 19)

SE requested that DOE analyze LVDTs in a separate rulemaking from liquid-immersed distribution transformers and MVDTs. It noted that the law defines them separately and that LVDT distribution transformers are used in applications that are different from those of MVDT distribution transformers. SE further noted that LVDT distribution transformers may warrant an expanded scope of coverage and encouraged DOE to reassess the range of kVAs covered, product definitions, exemptions, and loading points. (SE., No. 18 at p. 1) FPT suggested that DOE evaluate LVDT distribution transformers at a later date because this product category is not part of the court order. (FPT, No. 27 at p. 1) Rather, FPT believed that DOE should establish non-mandatory efficiencies for LVDT distribution transformers so that consumers who wish to purchase higher efficiency units can have a point of reference. (FPT, No. 27 at pp. 1–2)

CDA observed that the current efficiency levels for LVDT distribution transformers are at NEMA TP–1 levels and that the 2010 MVDT and liquid-immersed distribution transformer efficiency levels were set at approximately TSL 4. 72 FR 58239–40 (CDA, No. 17 at p. 3). CDA believed that it is appropriate for DOE to evaluate and adjust the minimum efficiency standards for LVDT distribution transformers, wherever cost-effective, to levels that are comparable to the 2010 levels for other [MVDT and liquid-immersed] distribution transformers. (CDA, No. 17 at p. 3) Earthjustice commented that DOE must revisit standards for LVDT distribution transformers as part of EPCA's requirement that standards be reevaluated not later than six years after issuance. Earthjustice noted that, on October 18, 2005, DOE codified the efficiency standards for LVDT distribution transformers that were set forth in EPACT 2005 (70 FR 60407) and that DOE must now publish, by October 18, 2011, either a new proposed standard or a determination that amended standards are not warranted. (Earthjustice, No. 20 at pp. 1–2) In joint comments, the Appliance Standards Awareness Project (ASAP), American Council for an Energy Efficient Economy (ACEEE), and Natural Resources Defense Council (NRDC) agreed with Earthjustice that DOE is obligated under EPCA to review the efficiency standards for liquid-immersed and MVDT distribution transformers and amend the efficiency standards for LVDT distribution transformers if justified. (ASAP/ACEEE/

NRDC, No. 28 at p. 5) HVOLT also believed that DOE should consider LVDT distribution transformers at this time. (HVOLT, No. 33 at p. 2) EEI believed that LVDT distribution transformers could be included in the rulemaking, since they are covered products under the statute and are now under a DOE regulatory purview. (EEI, Pub. Mtg. Tr., No. 34 at pp. 21, 27)

Without regard to whether DOE may have a statutory obligation to review standards for LVDTs, DOE has analyzed all three transformer types and is proposing standards for each in this rulemaking.

Schneider Electric suggested expanding coverage to include sealed units within the range of Design Lines 6 and 7: single-phase 15 and 25 kVA and three-phase 15 kVA distribution transformers. Further, it suggested that an additional three-phase 15 kVA design line, which would include SCOTT–T and OPEN DELTA designs, be created to meet the definition of sealed transformers. (SE., No. 7 at p. 2) DOE is not making this change because the EPACT 2005 definition of a distribution transformer and the definition currently codified at 10 CFR 431.192 both explicitly prohibit the inclusion of such transformers.

d. Negotiating Committee Discussion of Scope

Negotiation participants noted that both network/vault transformers and ''data center'' transformers may experience disproportionate difficulty in achieving higher efficiencies due to certain features that may affect consumer utility. (ABB, Pub. Mtg. Tr., No. 89 at p. 245) The definitions below had been proposed at various points by committee members and DOE seeks comment on both whether it would be appropriate to establish separate equipment classes for any of the following types and, if so, on how such classes might be defined such that it was not financially advantageous for consumers to purchase transformers in either class for general use.

i. A ''network transformer'' is one—

(i) Designed for use in a vault,

(ii) Designed for occasional submerged operation in water,

(iii) Designed to feed a system of variable capacity system of interconnected secondaries, and

(iv) Built per the requirements of IEEE C57.12.40-(year)

ii. A ''vault-type'' transformer is one—

(i) Designed for use in a vault,

(ii) Designed for occasional submerged operation in water, and

(iii) Built per the requirements of IEEE C57.12.23-(year) or IEEE C57.12.24-(year), respectively.

iii. Data center transformer means a three-phase low-voltage dry-type distribution transformer that—

(i) Is designed for use in a data center distribution system and has a nameplate identifying the transformer as being for this use only;

(ii) Has a maximum peak energization current (or in-rush current) less than or equal to four times its rated full load current multiplied by the square root of 2, as measured under the following conditions—

(iii) During energization of the transformer without external devices attached to the transformer that can reduce inrush current;

(iv) The transformer shall be energized at zero +/− 3 degrees voltage crossing of A phase. Five consecutive energization tests shall be performed with peak inrush current magnitudes of all phases recorded in every test. The maximum peak inrush current recorded in any test shall be used;

(v) The previously energized and then de-energized transformer shall be energized from a source having available short circuit current not less than 20 times the rated full load current of the winding connected to the source; and

(vi) The source voltage shall not be less than 5 percent of the rated voltage of the winding energized; and

(vii) Is manufactured with at least two of the following other attributes:

1. Listed by NRTL for a K-factor rating, as defined in UL standard 1561: 2011 Fourth Edition, greater than K–4;

2. Temperature rise less than 130°C with class 220 insulation or temperature rise less than 110°C with class 200 insulation;

3. A secondary winding arrangement that is not delta or wye (star);

4. Copper primary and secondary windings;

5. An electrostatic shield; or

6. Multiple outputs at the same voltage a minimum of 15° apart, which when summed together equal the transformer's input kVA capacity.

2. Equipment Classes

DOE divides covered equipment into classes by: (a) the type of energy used; (b) the capacity; or (c) any performance-related features that affect consumer utility or efficiency. (42 U.S.C. 6295(q)) Different energy conservation standards may apply to different equipment classes (ECs). For the preliminary analysis and for today's NOPR, DOE analyzed the same ten ECs as were used in the previous distribution transformers energy conservation standards rulemaking.[24] These ten equipment classes divided up the population of distribution transformers by:

(a) Type of transformer insulation—liquid-immersed or dry-type,

(b) Number of phases—single or three,

(c) Voltage class—low or medium (for dry-type units only), and

(d) Basic impulse insulation level (for medium-voltage, dry-type units only).

On August 8, 2005, the President signed into law EPACT 2005, which contained a provision establishing energy conservation standards for two of DOE's equipment classes—EC3 (low-voltage, single-phase, dry-type) and EC4 (low-voltage, three-phase, dry-type). With standards thereby established for low-voltage, dry-type distribution transformers, DOE no longer considered these two equipment classes for standards during the previous rulemaking. Since the current rulemaking is considering new standards for distribution transformers, DOE has preliminarily decided to also revisit low-voltage, dry-type distribution transformers to determine if higher efficiency standards are justified. Table IV.1 presents the ten equipment classes within the scope of this rulemaking analysis and provides the kVA range associated with each.

TABLE IV.1—DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES

EC #	Insulation	Voltage	Phase	BIL Rating	kVA Range
1	Liquid-Immersed	Medium	Single		10–833 kVA
2	Liquid-Immersed	Medium	Three		15–2500 kVA
3	Dry-Type	Low	Single		15–333 kVA
4	Dry-Type	Low	Three		15–1000 kVA

[24] See chapter 5 of the TSD for further discussion of equipment classes.

TABLE IV.1—DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES—Continued

EC #	Insulation	Voltage	Phase	BIL Rating	kVA Range
5	Dry-Type	Medium	Single	20–45kV BIL	15–833 kVA
6	Dry-Type	Medium	Three	20–45kV BIL	15–2500 kVA
7	Dry-Type	Medium	Single	46–95kV BIL	15–833 kVA
8	Dry-Type	Medium	Three	46–95kV BIL	15–2500 kVA
9	Dry-Type	Medium	Single	≥ 96kV BIL	75–833 kVA
10	Dry-Type	Medium	Three	≥ 96kV BIL	225–2500 kVA

ABB commented that the currently defined equipment classes do not cover the product scope as defined in 10 CFR part 431.192, which defines medium-voltage as between 601 V and 34.5 kV. Therefore, it recommended changing the equipment classes analyzed, or at least revising the definition in the CFR. (ABB, No. 14 at p. 9)

DOE is uncertain of how its current equipment classes are inconsistent with its published definition of ''medium-voltage dry-type'' and requests further comment on the issue.

a. Less-Flammable Liquid-Immersed Transformers

In the August 2006 standards NOPR, DOE solicited comments about how it should treat distribution transformers filled with an insulating fluid of higher flash point than that of traditional mineral oil. 71 FR 44369 (August 4, 2006). Known as ''less-flammable, liquid-immersed'' (LFLI) transformers, these units are marketed to some applications where a fire would be especially costly and traditionally served by the dry-type market, such as indoor applications.

During preliminary interviews with manufacturers, DOE was informed that LFLI transformers might offer the same utility as dry-type transformers since they were unlikely to catch fire. Manufacturers also stated that LFLI transformers could have a minor efficiency disadvantage relative to traditional liquid-immersed transformers because their more viscous insulating fluid requires more internal ducting to properly circulate.

In the October 2007 final rule, DOE determined that LFLI transformers should be considered in the same equipment class as traditional liquid-immersed transformers. DOE concluded that the design of a transformer (*i.e.,* dry-type or liquid-immersed) was a performance-related feature that affects the energy efficiency of the equipment and, therefore, dry-type and liquid-immersed should be analyzed separately. Furthermore, DOE found that LFLI transformers could meet the same efficiency levels as traditional liquid-immersed units. As a result, DOE did not separately analyze LFLI transformers, but relied on the analysis for the mineral oil liquid-immersed transformers. 72 FR 58202 (October 12, 2007).

For the preliminary analysis, DOE revisited the issue in light of additional research on LFLI transformers and conversations with manufacturers and industry experts. DOE first considered whether LFLI transformers offered the same utility as dry-type equipment, and came to the same conclusion as in the last rulemaking. While LFLI transformers can be used in some applications that historically use dry-type units, there are applications that cannot tolerate a leak or fire. In these applications, customers assign higher utility to a dry-type transformer. Since LFLI transformers can achieve higher efficiencies than comparable dry-type units, combining LFLIs and dry-types into one equipment class may result in standard levels that dry-type units are unable to meet. Therefore, DOE decided not to analyze LFLI transformers in the same equipment classes as dry-type distribution transformers.

Similarly, DOE revisited the issue of whether or not LFLI transformers should be analyzed separately from traditional liquid-immersed units. DOE concluded, once again, that LFLI transformers could achieve any efficiency level that mineral oil units could achieve. Although their insulating fluids are slightly more viscous, this disadvantage has little efficiency impact, and diminishes as efficiency increases and heat dissipation requirements decline. Furthermore, at least one manufacturer suggested that LFLI transformers might be capable of higher efficiencies than mineral oil units because their higher temperature tolerance may allow the unit to be downsized and run hotter than mineral oil units. Additionally, HVOLT agreed with DOE that high temperature liquid-filled transformer insulation systems have a similar space factor to mineral oil systems and should thus have similar losses. (HVOLT, No. 33 at p. 2) For these reasons, DOE believes that LFLI transformers would not be disproportionately affected by standards set in the liquid-immersed equipment classes. Therefore, DOE did not consider LFLI in a separate equipment class for the NOPR analysis.

b. Pole- and Pad-Mounted Liquid-Immersed Distribution Transformers

During negotiations, several parties raised the question of whether pole-mounted, pad-mounted, and possibly other types of liquid-immersed transformers should be considered in separate equipment classes. (ABB, Pub. Mtg. Tr., No. 89 at p. 230) DOE acknowledges that as standards rise, transformer types which previously had similar incremental costs may start to diverge and requests comment on whether and why separate equipment classes are warranted for pole-mounted, pad-mounted, and other types of liquid-immersed distribution transformers.

c. BIL Ratings in Liquid-Immersed Distribution Transformers

During negotiations, several parties raised the question of whether liquid-immersed distribution transformers should have standards set according to BIL rating, as do medium-voltage, dry-type distribution transformers. (ABB, Pub. Mtg. Tr., No. 89 at p. 218) DOE acknowledges that as standards rise, BIL ratings which previously had similar incremental costs may start to diverge and requests comment on whether and why separate equipment classes are warranted for liquid-immersed transformers of different BIL ratings. DOE requests particular comment on how many BIL bins are appropriate to cover the range and where the specific boundaries of those bins should lie.

3. Technology Options

The technology assessment provides information about existing technology options to construct more energy-efficient distribution transformers. There are two main types of losses in transformers: no-load (core) losses and load (winding) losses. Measures taken to reduce one type of loss typically increase the other type of losses. Some examples of technology options to improve efficiency include: (1) Higher-grade electrical core steels, (2) different conductor types and materials, and (3) adjustments to core and coil configurations.

In consultation with interested parties, DOE identified several technology options and designs for consideration. These technology options are presented in Table IV.2. Further detail on these technology options can be found in chapter 3 of the preliminary TSD.

TABLE IV.2—OPTIONS AND IMPACTS OF INCREASING TRANSFORMER EFFICIENCY

	No-load losses	Load losses	Cost impact
To decrease no-load losses			
Use lower-loss core materials	Lower	No change *	Higher.
Decrease flux density by:			
Increasing core cross-sectional area (CSA)	Lower	Higher	Higher.
Decreasing volts per turn	Lower	Higher	Higher.
Decrease flux path length by decreasing conductor CSA	Lower	Higher	Lower.
Use 120° symmetry in three-phase cores **	Lower	No change	TBD.
To decrease load losses			
Use lower-loss conductor material	No change	Lower	Higher.
Decrease current density by increasing conductor CSA	Higher	Lower	Higher.
Decrease current path length by:			
Decreasing core CSA	Higher	Lower	Lower.
Increasing volts per turn	Higher	Lower	Lower.

* Amorphous core materials would result in higher load losses because flux density drops, requiring a larger core volume.
** Sometimes referred to as a "hexa-transformer" design.

HYDRO-Quebec (IREQ) notified DOE that a new iron-based amorphous alloy ribbon for distribution transformers was developed that has enhanced magnetic properties while remaining ductile after annealing. Further, IREQ noted that a distribution transformer assembly using this technology has been developed. (IREQ, No. 10 at pp. 1–2)

DOE was not able to analyze the described material in the NOPR phase of the rulemaking, but intends to explore it further in the final rule. Two of the challenges facing amorphous steel include availability of the raw material and core manufacturing capacity. DOE seeks comment and analysis about amorphous steels that offer greater raw material availability and greater capacity to manufacture amorphous core steel.

a. Core Deactivation

As noted previously, core deactivation technology employs the concept that a system of smaller transformers can replace a single, larger transformer. For example, three 25 kVA transformers operating in parallel could replace a single 75 kVA transformer.

DOE understands that winding losses are proportionally smaller at lower load factors, but for any given current, a smaller transformer will experience greater winding losses than a larger transformer. As a result, those losses may be more than offset by the smaller transformer's reduced core losses. As loading increases, winding losses become proportionally larger and eventually outweigh the power saved by using the smaller core. At that point, the control unit (which consumes little power itself) switches on an additional transformer, which reduces winding losses at the cost of additional core losses. The control unit knows how efficient each combination of transformers is for any given loading, and is constantly monitoring the unit's power output so that it will use the optimal number of cores. In theory, there is no limit to the number of transformers that may operate in parallel in this sort of system, but cost considerations would imply an optimal number.

DOE spoke with a company that is developing a core deactivation technology. Noting that many dry-type transformers are operated at very low loadings a large percentage of the time (*e.g.,* a building at night), the company seeks to reduce core losses by replacing a single, traditional transformer with two or more smaller units that could be activated and deactivated in response to load demands. In response to load demand changes, a special unit controls the transformers and activates and/or deactivates them in real-time.

Although core deactivation technology has some potential to save energy over a real-world loading cycle, those savings might not be represented in the current DOE test procedure. Presently, the test procedure specifies a single loading point of 50 percent for liquid-immersed and MVDT transformers, and 35 percent for LVDT. The real gain in efficiency for core deactivation technology comes at loading points below the root mean square (RMS) loading specified in the test procedure, where some transformers in the system could be deactivated. At loadings where all transformers are activated, which may be the case at the test procedure loading, the combined core and coil losses of the system of transformers could exceed those of a single, larger transformer. This would result in a lower efficiency for the system of transformers compared to the single, larger transformer.

In response to the preliminary analysis, NEMA commented that core deactivation technology is unrelated to the design of a transformer, but rather is related to the system of which it is a part. Therefore, NEMA commented, it is outside the scope of this rulemaking, because all transformers must comply with DOE regulations. (NEMA, No. 13 at p. 3) ABB agreed that core deactivation technology is not related to the design of a transformer, but rather related to the design of the system in which the transformer is deployed. ABB noted that core deactivation technology input voltage source is disconnected from the transformer terminals, similar to a switchgear component and, as such, is not an integral element of the distribution transformer any more than a disconnect switch or circuit breaker. ABB commented that DOE does not consider other systems for energy efficiency, but if it is to look at core deactivation technology, perhaps it should also consider technologies that maintain the load power factor closer to unity. (ABB, No. 14 at pp. 3, 6)

Howard Industries (HI) commented that core deactivation technology does not currently exist for liquid-immersed transformers, and has not been evaluated for feasibility. In its opinion, core deactivation technology could cause several issues, such as flicker problems and in-rush current/surge protection. Additionally, HI believed that there are patent issues for this technology. For these reasons, HI recommended that DOE not consider core deactivation technology for liquid-immersed transformers. (HI, No. 23 at pp. 4, 11) Edison Electric Institute (EEI) agreed that core deactivation should not be considered for liquid-immersed transformers, which face significant load diversity because multiple buildings and/or homes can be served by a single transformer. EEI commented that, due to this load diversity, it is highly unlikely that core deactivation would provide energy savings for liquid-immersed transformers. (EEI, No. 29 at pp. 4–5)

HVOLT commented that core deactivation is not feasible. Based on HVOLT calculations, core deactivation only achieves fewer losses than a single, full-sized unit when loaded below 15 percent. Core deactivation also requires considerations for impedance, regulation, switching devices, and transformer reliability, making the technology unattractive for efficiency regulations. (HVOLT, No. 33 at pp. 2–3) Furthermore, HVOLT performed loading analyses of core deactivation technology and found that the only loading point where it beats traditional transformers was at zero percent. (HVOLT, Pub. Mtg. Tr., No. 34 at p. 60) However, Warner Power indicated that HVOLT's analysis was based on assumed numbers rather than actual designs and stated that core deactivation technology is more efficient than HVOLT's analysis indicated. (WP, Pub. Mtg. Tr., No. 34 at p. 62) Warner Power also commented that the 0.75 scaling factor did not accurately capture the efficiency of the smaller component transformers in a core deactivation system and asserted that it would prefer to see a linear scaling factor (WP, No. 30 at pp. 6–7, 11). Furthermore, Warner Power pointed out that core deactivation technology is better suited for many small loads than for large, discrete loads. The multiple, smaller loads create a smooth load profile throughout the day without sudden large demands. (WP, No. 30 at p. 7) Warner Power also commented that, for core deactivation technology, it is important to note that the secondary and tertiary component transformers do not typically power on at 33 percent and 66 percent load. Rather, the switching point is where the system operates with the lowest total losses and is specific to the transformer design. (WP, No. 30 at p. 7) Finally, Warner Power stated that core deactivation technology allows a transformer to achieve higher efficiency at low loading values. WP hypothesized that average power consumption will go down in buildings and transformer core losses will start to become more significant, thus making core deactivation technology more desirable. (WP, Pub. Mtg. Tr., No. 34 at p. 42)

NRECA and the NRECA Transmission & Distribution Engineering Committee (T&DEC) commented that core deactivation technology would be extremely difficult to successfully implement from an economical viewpoint. (NRECA/T&DEC, No. 31 and 36 at p. 2) Southern Company (SC) agreed and noted that core deactivation technology does not seem practical or cost-effective because it would use more materials than a single transformer, which would increase the weight and cost of the unit. SC further noted that the increased weight could be problematic for pole-mounted transformers. (SC, No. 22 at p. 3)

FPT commented that DOE should not consider core deactivation in the efficiency standard rulemaking at this time because it is only advantageous in certain situations with low loading requirements, and thus only represents a small portion of the market. (FPT, No. 27 at p. 3) Rather, FPT suggested that DOE encourage users to de-energize the LVDT from the primary switch/breaker. FPT also noted that the technology would face challenges with medium-voltage transformers, such as pre-strikes, re-strikes, ferroresonance, and reducing the life of the primary circuit sectionalizing device. (FPT, No. 27 at p. 3)

Berman Economics was interested to know if DOE would also be looking at the potential differences in stress and wear on the transformer as one is activating and deactivating the core deactivation transformer. (BE, Pub. Mtg. Tr, No. 34 at p. 62)

DOE appreciates all of the comments from interested parties regarding core deactivation technology. DOE understands that core deactivation technology is most easily implemented in LVDT distribution transformer designs. Implementing core deactivation technology in medium-voltage distribution transformers is possible, but poses difficulties for switching the primary and secondary connections. For the NOPR, DOE has not fully quantified these difficulties because it did not directly analyze core deactivation technology, although DOE believes it may be possible to evaluate the technology using its existing transformer designs. DOE also acknowledges that operating a core deactivation bank of transformers instead of a single unit may save energy and lower LCC for certain consumers. At present, however, DOE is adopting the position that each of the constituent transformers must comply with the energy conservation standards under the scope of the rulemaking.

b. Symmetric Core

DOE understands that several companies worldwide are commercially producing three-phase transformers with symmetric cores—those in which each leg of the transformer is identically connected to the other two. The symmetric core uses a continuously wound core with 120-degree radial symmetry, resulting in a triangularly shaped core when viewed from above. In a traditional core, the center leg is magnetically distinguishable from the other two because it has a shorter average flux path to each. In a symmetric core, however, no leg is magnetically distinguishable from the other two.

One manufacturer of symmetric core transformers cited several advantages to the symmetric core design. These include reduced weight, volume, no-load losses, noise, vibration, stray magnetic fields, inrush current, and power in the third harmonic. Thus far, DOE has seen limited cost and efficiency data for only a few symmetric core units from testing done by manufacturers. DOE has not seen any designs for symmetric core units modeled in a software program.

DOE understands that, because of zero-sequence fluxes associated with wye-wye connected transformers, symmetric core designs are best suited to delta-delta or delta-wye connections. While traditional cores can circumvent the problem of zero-sequence fluxes by introducing a fourth or fifth unwound leg, core symmetry makes extra legs inherently impractical. Another way to mitigate zero-sequence fluxes comes in the form of a tertiary winding, which is delta-connected and has no external connections. This winding is dormant when the transformer's load is balanced across its phases. Although symmetric core designs may, in theory, be made tolerant of zero-sequence fluxes by employing this method, this would come at extra cost and complexity.

Using this tertiary winding, DOE believes that symmetric core designs can service nearly all distribution transformer applications in the United States. Most dry-type transformers have a delta connection and would not require a tertiary winding. Similarly, most liquid-immersed transformers serving the industrial sector have a delta connection. These market segments could use the symmetric core design without any modification for a tertiary winding. However, in the United States most utility-operated distribution transformers are wye-wye connected. These transformers would require the tertiary winding in a symmetric core design.

DOE understands that symmetric core designs are more challenging to manufacture and require specialized equipment that is currently uncommon in the industry. However, DOE did not find a reasonable basis to screen this technology option out of the analysis, and is aware of at least one manufacturer producing dry-type symmetric core designs commercially in the United States.

For the preliminary analysis, DOE lacked the data necessary to perform a thorough engineering analysis of symmetric core designs. To generate a cost-efficiency relationship for symmetric core design transformers, DOE made several assumptions. DOE adjusted its traditional core design models to simulate the cost and efficiency of a comparable symmetric core design. To do this, DOE reduced core losses and core weight while increasing labor costs to approximate the symmetric core designs. These adjustments were based on data received from manufacturers, published literature, and through conversations with manufacturers. Table IV.3 indicates the range of potential adjustments for each variable that DOE considered and the mean value used in the analysis.

TABLE IV.3—SYMMETRIC CORE DESIGN ADJUSTMENTS

Range	[Percentage changes]		
	Core losses (W)	Core weight (lbs)	Labor hours
Minimum	−0.0	−12.0	+10.0
Mean	−15.5	−17.5	+55.0
Maximum	−25.0	−25.0	+100.0

DOE applied the adjustments to each of the traditional three-phase transformer designs to develop a cost-efficiency relationship for symmetric core technology. DOE did not model a tertiary winding for the wye-wye connected liquid-immersed design lines (DLs). Based on its research, DOE believes that the losses associated with the tertiary winding may offset the benefits of the symmetric core design and that the tertiary winding will add cost to the design. Therefore, DOE modeled symmetric core designs for the three-phase, liquid-immersed design lines without a tertiary winding to examine the impact of symmetric core technology on the subgroup of applications that do not require the tertiary winding.

NPCC and NEEA jointly commented that DOE should revise its assumptions about costs and limitations of symmetric core designs in accordance with information provided by manufacturers of these technologies. (NPCC/NEEA, No. 11 at p. 2) Furthermore, NPCC and NEEA noted that DOE should revise its analysis for symmetric core designs to account for labor costs that mirror those of conventional core designs. NPCC and NEEA recommended that DOE request additional data from manufacturers that are producing this technology. (NPCC/NEEA, No. 11 at pp. 4, 6)

Hex Tec (HEX) commented that DOE should consider a symmetric core design using amorphous core steel in its evaluation. (HEX, No. 35 at p. 1) It noted that there are several variations of the symmetric core design being made around the world and that licenses are available. Furthermore, it commented that amorphous metal suppliers are emerging in India and China, concluding that there are no barriers to adopting symmetric core technology with an amorphous core. (HEX, No. 35 at p. 1) Hex Tec pointed out that amorphous units up to 3 MVA in size have been produced using Evans distributed gap core construction, but are labor intensive and difficult to produce, and concluded that amorphous designs are easier to make using a symmetric core. (HEX, No. 35 at p. 1) Finally, Hex Tec submitted a letter written by the Vice President of Research & Development at Metglas that indicates that symmetric core units using amorphous steel of 15 to 100 kVA demonstrated core losses of 0.13 Watts/lb at an induction of 1.2 T. The letter also noted that audible sound levels were low. (HEX, No. 35 at p. 14)

Hammond (HPS) commented that its analytical and prototype work indicated that symmetric core designs do not experience a core loss advantage but do have higher manufacturing costs. (HPS, No. 3 at p. 2) However, Hex Tec commented that it builds symmetric cores with labor costs and material savings that are comparable to those incurred by conventional construction. (HEX, Pub. Mtg. Tr., No. 34 at p. 25) Hex Tec noted that the equipment to produce symmetric wound cores is significantly less expensive than flat stack steel equipment and that the labor production times are lower. (HEX, Pub. Mtg. Tr., No. 34 at p. 52) Hex Tec added that labor requirements, both TAC time and process times, are lower for symmetric core designs than for conventional designs. (HEX, No. 35 at p. 2)

Hex Tec submitted data showing that the weight of three-phase, 75 kVA LVDT symmetric core designs ranged from 390 to 600 pounds between 98.6 and 99.2 percent efficiency. These weights are lower than the weights of comparably efficient designs using conventional cores. (HEX, No. 35 at p. 7) Hex Tec also submitted data comparing the efficiency, dimensions, core and coil material content, and cost of several conventional designs for three-phase, 75 kVA LVDT units to those of otherwise identical symmetric core designs. (HEX, No. 35 at p. 8) Hex Tec noted it took the same amount of labor time as a major conventional-design manufacturer to produce a three-phase 75 kVA LVDT rated at CSL3,[25] and that it was able to do so with lower material costs. (HEX, Pub. Mtg. Tr., No. 34 at p. 110) Hex Tec also submitted data showing comparisons between the weight, losses, and costs of conventional core designs and symmetric core designs at 1000

[25] ''Candidate Standard Levels'' (CSLs) are analogous to the Efficiency Levels (ELs) DOE utilizes together in the NOPR to create Trial Standard Levels (TSLs). This particular commenter refers to CSL3 from the 2007 rulemaking, not the present one.

kVA and 2000 kVA for MVDTs. (HEX, No. 35 at pp. 9–10)

Warner Power pointed out that recent improvements in the manufacturing process for symmetric core designs, leveraged by increasing volumes, will bring labor costs down to approximately 10 percent below labor costs for conventional cores. (WP, No. 30 at p. 3) Warner Power commented that symmetric cores use a wound core with no scrap and approximately 15 percent lower weight than that of conventional cores. (WP, No. 30 at p. 3) Warner felt that DOE's symmetric core analysis contained some significant errors that would generate the wrong output, and that the manufacturing cost estimates for symmetric cores were overstated. (WP, No. 30 at p. 9; WP Pub. Mtg. Tr., No. 34 at p. 111)

Power Partners commented that DOE should not set a standard based on symmetric core designs because they are not common in the industry and could place an unreasonable burden on smaller manufacturers who would be unable to invest in the equipment necessary for the technology. (PP, No. 19 at p. 2) NEMA agreed, commenting that symmetric core is in its infancy and has low penetration in the industry and should not be introduced into the regulation until it has been proven in the marketplace. (NEMA, No. 13 at p. 3) FPT commented that symmetric core technology should not be used as the basis for increasing efficiency levels and noted that, while the technology may be advantageous in some areas, it may present problems with larger transformers. (FPT, No. 27 at pp. 3–4, 13) Warner Power disagreed and stated that symmetric core designs and core deactivation technology should be included in the scope of DOE's analysis, recommending several symmetric core and core deactivation design option combinations. (WP, No. 30 at p. 9)

NEEA reiterated that symmetric core manufacturers have stated that there should not be any patent concerns for the technology, since it is not yet patented. (NEEA, No. 11 at p. 4; NEEA, Pub. Mtg. Tr., No. 34 at p. 261) Howard Industries disagreed and commented that DOE should not consider symmetric core technology because it is patented by Hexaformer AB of Sweden, which would result in increased licensing costs. (HI, No. 23 at pp. 3–4, 6–7, 11) Furthermore, HI noted that no manufacturers in North America currently produce the design for liquid-immersed units. (HI, No. 23 at pp. 3–4, 6–7, 11) HI also pointed out that Hexaformer AB does not produce units higher than 200 kVA and 24 kV, whereas most utilities require larger kVA sizes and 35 kV. (HI, No. 23 at pp. 3–4, 6–7, 11) Finally, Howard commented that all efficiency improvements for symmetric core liquid-immersed designs are theoretical at this point. (HI, No. 23 at pp. 3–4, 6–7, 11)

Southern Company commented that symmetric core technology is not feasible for utility applications because they require wye-wye connections, while symmetric cores have a delta connection. SC noted that, while a tertiary winding may enable the symmetric core design to be connected in the system, SC has had trouble in the past with tertiary windings and has discontinued purchasing transformers that use them. (SC, No. 22 at p. 2) Howard Industries and HVOLT also noted that most utility transformers are wye-wye connected and would need a delta tertiary winding to use symmetric core technology, which would drive down efficiency while increasing costs. (HI, No. 23 at pp. 3–4, 6–7, 11; HVOLT, Pub. Mtg. Tr., No. 34 at p. 50; HVOLT, Pub. Mtg. Tr., No. 34 at p. 50)

DOE attempts to consider all designs that are technologically feasible and practicable to manufacture and believes that symmetric core designs can meet these criteria. However, DOE has not been able to obtain or produce sufficient data to modify its analysis of symmetric cores since the preliminary analysis. Therefore, although not screened out, DOE has not considered symmetric core designs for its NOPR analyses. DOE welcomes comment and submission of engineering data that would be useful in analyzing symmetric core designs in the final rule.

c. Intellectual Property

In setting standards, DOE seeks to analyze the efficiency potentials of commercially available technologies and working prototypes as well as the availability of those technologies to the market at-large. If certain market participants own intellectual property that enable them to reach efficiencies that other participants practically cannot, amended standards may reduce the competitiveness of the market.

In the case of distribution transformers, stakeholders have raised potential intellectual property concerns surrounding both symmetric core technology and amorphous metals in particular. DOE currently understands that symmetric core technology itself is not proprietary, but that one of the more commonly employed methods of production is the property of the Swedish company Hexaformer AB. However, Hexaformer AB's method is not the only one capable of producing symmetric cores. Moreover, Hexaformer AB and other companies owning intellectual property related to the manufacture of symmetric core designs have demonstrated an eagerness to license such technology to others that are using it to build symmetric core transformers commercially today.

Warner Power commented that the well-known symmetric core design (Hexaformers) is subject to worldwide patents for the core winding and assembly process, but multiple licenses have been authorized and the IP owner has indicated it will entertain additional licenses. The basic design concept is not patented, and several other manufacturers make symmetric cores, so patents should not be a limiting factor. (WP, No. 30 at pp. 3–4)

EEI noted that, if certain higher-efficiency designs are covered by patents, then the number of manufacturers may decrease, which would increase transformer prices. It recommended that DOE discuss any relevant patents and indicate whether they will be in place after 2016. (EEI, No. 29 at p. 10)

DOE understands that symmetric core technology may ultimately offer a lower-cost path to higher efficiency, at least in certain applications, and that few symmetric cores are produced in the United States. However, DOE notes again that it has been unable to secure data that are sufficiently robust for use as the basis for an energy conservation standard, but encourages interested parties to submit data that would assist in DOE's analysis of symmetric core technology.

B. Screening Analysis

DOE uses the following four screening criteria to determine which design options are suitable for further consideration in a standards rulemaking:

1. *Technological feasibility.* Technologies incorporated in commercial products or in working prototypes will be considered to be technologically feasible.

2. *Practicability to manufacture, install, and service.* If mass production of a technology in commercial products and reliable installation and servicing of the technology could be achieved on the scale necessary to serve the relevant market at the time of the effective date of the standards, then that technology will be considered practicable to manufacture, install, and service.

3. *Impacts on product utility to consumers.* If a technology is determined to have significant adverse impact on the utility of the product to significant subgroups of consumers, or

result in the unavailability of any covered product type with performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as products generally available in the United States at the time, it will not be considered further.

4. *Safety of technologies.* If it is determined that a technology will have significant adverse impacts on health or safety, it will not be considered further. (10 CFR part 430, subpart C, appendix A)

In the preliminary analysis, DOE identified the technologies for improving distribution transformer efficiency that were under consideration. DOE developed this initial list of design options from the technologies identified in the technology assessment. Then DOE reviewed the list to determine if the design options are practicable to manufacture, install, and service; would adversely affect equipment utility or equipment availability; or would have adverse impacts on health and safety. In the engineering analysis, DOE only considered those design options that satisfied the four screening criteria. The design options that DOE did not consider because they were screened out are summarized in Table IV.4.

TABLE IV.4—DESIGN OPTIONS SCREENED OUT OF THE ANALYSIS

Design option excluded	Eliminating screening criteria
Silver as a Conductor Material	Practicability to manufacture, install, and service.
High-Temperature Superconductors	Technological feasibility; Practicability to manufacture, install, and service.
Amorphous Core Material in Stacked Core Configuration	Technological feasibility; Practicability to manufacture, install, and service.
Carbon Composite Materials for Heat Removal	Technological feasibility.
High-Temperature Insulating Material	Technological feasibility.
Solid-State (Power Electronics) Technology	Technological feasibility; Practicability to manufacture, install, and service.
Nanotechnology Composites	Technological feasibility.

Chapter 4 of the TSD discusses each of these screened-out design options in more detail. The chapter also includes a list of emerging technologies that could impact future distribution transformer manufacturing costs.

Multiple interested parties commented that they agreed with the technology options screened out of the analysis by DOE. (EEI, No. 29 at p. 5; HI, No. 23 at p. 5; NPCC/NEEA, No. 11 at p. 3) Metglas concurred that using amorphous metals in a stack core configuration is technically infeasible. (Metglas, Pub. Mtg. Tr., No. 34 at p. 66) Howard Industries also recommended that DOE screen out symmetric core designs and core deactivation technology from their analysis based on proprietary concerns. (HI, No. 23 at p. 5)

DOE appreciates the feedback and remains interested in advances that would allow a currently screened technology to be considered as a design option. As for symmetric core designs, DOE has not screened this technology out because it is aware that manufacturers around the world are building and selling such transformers. However, without additional information regarding the technology, DOE has been unable to fully evaluate this as a design option.

1. Nanotechnology Composites

DOE understands that the nanotechnology field is actively researching ways to produce bulk material with desirable features on a molecular scale. Some of these materials may have high resistivity, high permeability, or other properties that make them attractive for use in electrical transformers. DOE knows of no current commercial efforts to employ these materials in distribution transformers and no prototype designs using this technology, but welcomes comment on such technology and its implications for the future of the industry.

NEMA and ABB Transformers both commented that, because nanotechnology composite technology is not commercially available in the U.S., manufacturers cannot discuss it publicly. (NEMA, No. 13 at p. 4; ABB, No. 14 at p. 7) Howard Industries, Inc. was unaware of any nanotechnology composite technology for distribution transformers. (HI, No. 23 at p. 4)

DOE appreciates confirmatory feedback, and does not propose to consider nanotechnology composites in the current rulemaking.

C. Engineering Analysis

The engineering analysis develops cost-efficiency relationships for the equipment that are the subject of a rulemaking by estimating manufacturer costs of achieving increased efficiency levels. DOE uses manufacturing costs to determine retail prices for use in the LCC analysis and MIA. In general, the engineering analysis estimates the efficiency improvement potential of individual design options or combinations of design options that pass the four criteria in the screening analysis. The engineering analysis also determines the maximum technologically feasible energy efficiency level.

DOE must consider those distribution transformers that are designed to achieve the maximum improvement in energy efficiency that the Secretary of Energy determines to be technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) Therefore, an important role of the engineering analysis is to identify the maximum technologically feasible efficiency level. The maximum technologically feasible level is one that can be reached by adding efficiency improvements and/or design options, both commercially feasible and in prototypes, to the baseline units. DOE believes that the design options comprising the maximum technologically feasible level must have been physically demonstrated in a prototype form to be considered technologically feasible.

In general, DOE can use three methodologies to generate the manufacturing costs needed for the engineering analysis. These methods are:

(1) The design-option approach—reporting the incremental costs of adding design options to a baseline model;

(2) The efficiency-level approach—reporting relative costs of achieving improvements in energy efficiency; and

(3) The reverse engineering or cost assessment approach—involving a ‘‘bottom up’’ manufacturing cost assessment based on a detailed bill of

materials derived from transformer teardowns.

DOE's analysis for the distribution transformers rulemaking is based on the design-option approach, in which design software is used to assess the cost-efficiency relationship between various design option combinations. This is the same approach that was taken in the previous rulemaking for distribution transformers.

1. Engineering Analysis Methodology

When developing its engineering analysis for distribution transformers, DOE divided the covered equipment into equipment classes. As discussed, distribution transformers are classified by insulation type (liquid-immersed or dry-type), number of phases (single or three), primary voltage (low-voltage or medium-voltage for dry-types) and basic impulse insulation level (BIL) rating (for dry-types). Using these transformer design characteristics, DOE developed ten equipment classes. Within each of these equipment classes, DOE further classified distribution transformers by their kilovolt-ampere (kVA) rating. These kVA ratings are essentially size categories, indicating the power handling capacity of the transformers. For DOE's rulemaking there are over 100 kVA ratings across all ten equipment classes.

DOE recognized that it would be impractical to conduct a detailed engineering analysis on all kVA ratings, so it sought to develop an approach that simplified the analysis while retaining reasonable levels of accuracy. DOE consulted with industry representatives and transformer design engineers to develop an understanding of the construction principles for distribution transformers. It found that many of the units share similar designs and construction methods. Thus, DOE simplified the analysis by creating engineering design lines (DLs), which group kVA ratings based on similar principles of design and construction. The DLs subdivide the equipment classes, to improve the accuracy of the engineering analysis. These DLs differentiate the transformers by insulation type (liquid-immersed or dry-type), number of phases (single or three), and primary insulation levels for medium-voltage, dry-type (three different BIL levels).

After developing its DLs, DOE then selected one representative unit from each DL for study in the engineering analysis, greatly reducing the number of units for direct analysis. For each representative unit, DOE generated hundreds of unique designs by contracting with Optimized Program Services, Inc. (OPS), a software company specializing in transformer design since 1969. The OPS software used three primary inputs that it received from DOE, (1) a design option combination, which included core steel grade, primary and secondary conductor material, and core configuration; (2) a loss valuation combination; and (3) material prices. For each representative unit, DOE examined anywhere from 8 to 16 design option combinations and for each design option combination, the OPS software generated 518 designs based off of unique loss valuation combinations. These loss valuation combinations are known in industry as A and B evaluation combinations and represent a customer's present value of future losses in a transformer core and winding, respectively. For each design option combination and A and B combination, the OPS software generated an optimized transformer design based on the material prices that were also part of the inputs. Consequently, DOE obtained thousands of transformer designs for each representative unit. The performance of these designs ranged in efficiency from a baseline level, equivalent to the current distribution transformer energy conservation standards, to a theoretical max-tech efficiency level.

After generating each design, DOE used the outputs of the OPS software to help create a manufacturer selling price (MSP). The material cost outputs of the OPS software, along with labor estimates were marked up for scrap factors, factory overhead, shipping, and non-production costs to generate an MSP for each design. Thus, DOE obtained a cost versus efficiency relationship for each representative unit. Finally, after DOE had generated the MSPs versus efficiency relationship for each representative unit, it extrapolated the results the other, unanalyzed, kVA ratings within that same engineering design line.

2. Representative Units

For the preliminary analysis, DOE analyzed 13 DLs that cover the range of equipment classes within the distribution transformer market. Within each DL, DOE selected a representative unit to analyze in the engineering analysis. A representative unit is meant to be an idealized distribution transformer typical of those used in high volume applications. Table IV.5 outlines the design lines and representative units selected for each equipment class.

TABLE IV.5—ENGINEERING DESIGN LINES AND REPRESENTATIVE UNITS FOR ANALYSIS

EC*	DL	Type of distribution transformer	kVA Range	Representative unit for this engineering design line
1	1	Liquid-immersed, single-phase, rectangular tank	10–167	50 kVA, 65 °C, single-phase, 60Hz, 14400V primary, 240/120V secondary, rectangular tank.
	2	Liquid-immersed, single-phase, round tank	10–167	25 kVA, 65 °C, single-phase, 60Hz, 14400V primary, 120/240V secondary, round tank.
	3	Liquid-immersed, single-phase	250–833	500 kVA, 65 °C, single-phase, 60Hz, 14400V primary, 277V secondary.
2	4	Liquid-immersed, three-phase	15–500	150 kVA, 65 °C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary.
	5	Liquid-immersed, three-phase	750–2500	1500 kVA, 65 °C, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary.
3	6	Dry-type, low-voltage, single-phase	15–333	25 kVA, 150 °C, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL.
4	7	Dry-type, low-voltage, three-phase	15–150	75 kVA, 150 °C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL.
	8	Dry-type, low-voltage, three-phase	225–1000	300 kVA, 150 °C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL.

TABLE IV.5—ENGINEERING DESIGN LINES AND REPRESENTATIVE UNITS FOR ANALYSIS—Continued

EC*	DL	Type of distribution transformer	kVA Range	Representative unit for this engineering design line
6	9	Dry-type, medium-voltage, three-phase, 20–45kV BIL	15–500	300 kVA, 150 °C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL.
	10	Dry-type, medium-voltage, three-phase, 20–45kV BIL	750–2500	1500 kVA, 150 °C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL.
8	11	Dry-type, medium-voltage, three-phase, 46–95kV BIL	15–500	300 kVA, 150 °C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL.
	12	Dry-type, medium-voltage, three-phase, 46–95kV BIL	750–2500	1500 kVA, 150 °C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL.
10	13	Dry-type, medium-voltage, three-phase, 96–150kV BIL	225–2500	2000 kVA, 150 °C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 125kV BIL.

* EC = Equipment Class

ABB commented that the definition of design lines for equipment class 4 leaves an uncovered kVA range from 150 kVA to 225 kVA, and recommended that DOE extend the scope of DL 8 to be 150–1000 kVA. (ABB, No. 14 at p. 12) In view of the ABB comment, DOE would like to clarify that DL 7 covers kVA ratings up through 150 kVA, and that DL 8 covers kVA ratings beginning with 225 kVA. DOE does not specify any ratings in between 150 and 225 kVA because it is not aware of any standard ratings between these two ratings. Furthermore, 10 CFR 431.196(a) states that low-voltage dry-type distribution transformers with kVA ratings not appearing in the table [of designated kVA ratings and efficiencies] shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating. Therefore, DOE has not altered the design lines for low-voltage dry-type transformers.

Additionally, ABB had several recommendations for DOE regarding representative units. First, ABB commented that DOE correctly noted in the 2007 rulemaking that BIL does not impact efficiency for liquid-immersed transformers as significantly as it impacts MVDT units. However, since DOE does not separate out the liquid-immersed efficiency levels by BIL and performs its analysis on the 15 kV voltage class, it understates the energy savings for units with a higher BIL and makes it more difficult for these units to meet the efficiency standard. ABB recommended that DOE analyze representative units for liquid-immersed design lines in the 200 kV BIL class, such as a 34500 V (200 BIL) unit. (ABB, No. 14 at pp. 7–8) For the liquid-immersed design lines, ABB recommended that DOE consider a 150 kVA (200 BIL) single-phase representative unit and a 30 kVA (200 BIL) three-phase representative unit to better represent the range of BILs covered and to provide for more accurate scaling. (ABB, No. 14 at p. 11) To improve the scaling within the LVDT equipment classes, ABB also recommended that DOE consider a 100 kVA (10 BIL) single-phase representative unit and a 25 kVA (10 BIL) three-phase unit. (ABB, No. 14 at p. 12) For DL13, ABB recommended that DOE consider a representative unit in the 200 kV BIL class, such as 34500 V (200 BIL). For EC 10, ABB recommended that DOE consider a representative unit at 200 kV BIL in order to analyze a unit at the upper limit of the BIL rating for the equipment class. (ABB, No. 14 at p. 10)

ABB also disagreed with the assumption that single-phase MVDT units have one-third the losses of three-phase MVDT units and commented that DOE should directly analyze single-phase MVDT units. It further noted that this assumption was not made for liquid-immersed or LVDT units. (ABB, No. 14 at pp. 5, 10) ABB suggested that DOE analyze several single-phase MVDT representative units including the following: 50 kVA (45 BIL), 300 kVA (45 BIL), 50 kVA (95 BIL), and 300 kVA (95 BIL). ABB also recommended that DOE analyze 150 kVA (200 BIL) and 500 kVA (200 BIL) units if DOE does not change the definition of EC 9, or 50 kVA (200 BIL) and 300 kVA (200 BIL) if it does change the definition of EC 9 to align with 10 CFR part 431.192. (ABB, No. 14 at p. 10) To provide for better scaling, ABB recommended that DOE consider the following representative units for three-phase MVDT: 30 kVA (45 BIL), and 30 kVA (95 BIL). ABB also recommended that DOE analyze 500 kVA (200 BIL) units if it does not change the definition of EC10, or 30 kVA (200 BIL) and 300 kVA (200 BIL) units if it does change the definition of EC9 to align with 10 CFR 431.192. (ABB, No. 14 at p. 10)

NEMA commented that it found the representative unit for DL 5, DL 13, and the units for the single-phase liquid-immersed design lines all to be satisfactory. (NEMA, No. 13 at p. 4) However, NEMA stated that DOE should consider at least one representative unit for each of the three equipment classes for single-phase medium-voltage dry-type transformers. (NEMA, No. 13 at p. 5) NEMA also suggested an additional representative unit for each of the three LVDT design lines. (NEMA, No. 13 at p. 5) For DL1, NEMA commented that DOE should examine an additional representative unit of 167 kVA, 65 degrees Celsius, single-phase, 60 Hz, 14400V primary, 240/120 secondary, rectangular tank. (NEMA, No. 13 at p. 4) For DL2, NEMA felt that DOE should examine an additional representative unit of 100 kVA, 65 degrees Celsius, single-phase, 60 Hz, 14400V primary, 120/240 secondary, round tank. (NEMA, No. 13 at p. 5)

Howard Industries also recommended several representative units for DOE to consider. Howard noted that it is not optimum to require the same efficiency for the entire range of BIL ratings for liquid-immersed distribution transformers. It suggested that DOE examine representative units with higher BIL ratings for the single-phase liquid-immersed design lines, such as 19920 V (150 kV BIL), as well as for dual primary voltage ratings, such as 7200 × 19920 V primary voltages. (HI, No. 23 at p. 5) Also, Howard Industries recommended that DOE consider a representative unit for DL5 with a 150 kV BIL and a dual voltage primary, such as 12470GRDY/7200 x 24500GRDY/19920. (HI, No. 23 p. 5) Further, it commented that large three-phase liquid-immersed transformers with low-voltage ratings, such as 208Y/120, should be examined because these designs are difficult to manufacture even under the present efficiency standards. (HI, No. 23 at p. 5) Finally, Howard Industries noted that DOE may need to consider additional representative units in order to perform accurate scaling for pole type transformers. It recommended that DOE consider kVA ranges of 10–50 kVA, 75–167 kVA, and 250–833 kVA for accurate scaling of pole-mount units. (HI, No. 23 at p. 8)

Power Partners noted that it could not determine the BIL rating for design line 1. (PP, Pub. Mtg. Tr., No. 34 at p. 71) Howard Industries and Power Partners both supported using 125 BIL 14400 volt designs for design lines 1–3. (PP, Pub. Mtg. Tr., No. 34 at p. 72; HI, Pub. Mtg. Tr., No. 34 at p. 72) NRECA and T&DEC commented that the 14.4 kV primary voltage selected for DOE's analysis of design lines 1 through 3 is appropriate in that it represents a large portion of the market. However, they commented that DOE should explain how other voltages above and below this level would be impacted. (NRECA/T&DEC, No. 31 and 36 at p. 3) In DL 3, PP suggested analyzing the smallest and largest transformers in addition to the midpoint. (PP, Pub. Mtg. Tr., No. 34 at p. 136) Power Partners would support the use of 14400 volt 125 BIL coil voltage as the means of analysis for all liquid-filled design lines. (PP, Pub. Mtg. Tr., No. 34 at p. 83) PP would also support 14400 volts in the design lines for single-phase liquid-immersed transformers. (PP, Pub. Mtg. Tr., No. 34 at p. 71) It commented that DOE should increase the voltage of its liquid-immersed representative units to 34500GY/19920 (150 BIL) or, at a minimum, consider 14400/24940Y (125 BIL). Power Partners noted that it is more difficult to meet the efficiency standards at these higher voltages, and suggested detailed specifications for revision to the representative units for DL2 and DL3. (PP, No. 19 at pp. 2–3)

In regards to the representative unit for DL13, FPT commented that dry-type transformers with primaries rated for 125 kV BIL are more commonly rated at 24900V and 150 kV BIL units typically have 34500 volt primaries. (FPT, No. 27 at p. 14) Hex Tec stated that, for DL 13, ''MVDT three-phase units, 2000 kVA 12470, 480/277 with a 95 kV BIL is the workhorse of that market.'' (HEX, Pub. Mtg. Tr., No. 34 at p. 81) For 96–150 kV BIL, FPT believed that 24900 or 24940 volts would be more appropriate for the primary voltage of the representative unit in DL13. (FPT, Pub. Mtg. Tr., No. 34 at p. 81) Hammond commented that the representative unit for DL13 should have a primary of 24940 V Delta for the 125 kV BIL. (HPS, No. 3 at p. 3)

Schneider Electric (SE) suggested adding another design line for low-voltage three-phase units at 15 kVA. SE felt that this would be beneficial to the national impact analysis because that design line is readily available in the marketplace. (SE, Pub. Mtg. Tr., No. 34 at p. 83) SE also commented that DOE should analyze two representative units for each of the three existing LVDT design lines. It recommended that DOE split the analyzed kVA ranges into two ranges and analyze a representative unit in each. (SE, No. 18 at p. 7)

Central Moloney commented that the 25 kVA pole unit is shown as 240/120 but that the standard is 120/240. (CM, Pub. Mtg. Tr., No. 34 at p. 72)

Overall, NPCC and NEEA commented that the representative units selected should accurately represent products that are being sold in the marketplace, and recommended that DOE adjust its analysis based on feedback from manufacturers. (NPCC/NEEA, No. 11 at p. 5)

In view of the above comments, DOE slightly modified its representative units for the NOPR analysis. For the NOPR, DOE analyzed the same 13 representative units as in the preliminary analysis, but also added a design line, and therefore representative unit, by splitting the former design line 13 into two new design lines, 13A and 13B. This new representative unit is shown in Table IV.6. The representative units selected by DOE were chosen because they comprise high volume segments of the market for their respective design lines and also provide, in DOE's view, a reasonable basis for scaling to the unanalyzed kVA ratings. DOE chooses certain designs to analyze as representative of a particular design line or design lines because it is impractical to analyze all possible designs in the scope of coverage for this rulemaking. DOE will consider extending its direct analysis further to substantiate the efficiency standard proposed for the final rule and will publish sensitivity results to help assess the accuracy of its analysis in the areas not directly analyzed. DOE also notes that as a part of the negotiations process, DOE has worked directly with multiple interested parties to develop a new scaling methodology for the NOPR that addresses some of the aforementioned interested party concerns regarding scaling.

TABLE IV.6—ENGINEERING DESIGN LINES (DLS) AND REPRESENTATIVE UNITS FOR ANALYSIS

EC*	DL	Type of distribution transformer	kVA Range	Representative unit for this engineering design line
1	1	Liquid-immersed, single-phase, rectangular tank	10–167	50 kVA, 65 °C, single-phase, 60Hz, 14400V primary, 240/120V secondary, rectangular tank, 95kV BIL.
	2	Liquid-immersed, single-phase, round tank	10–167	25 kVA, 65 °C, single-phase, 60Hz, 14400V primary, 120/240V secondary, round tank, 125 kV BIL.
	3	Liquid-immersed, single-phase	250–833	500 kVA, 65 °C, single-phase, 60Hz, 14400V primary, 277V secondary, 150kV BIL.
2	4	Liquid-immersed, three-phase	15–500	150 kVA, 65 °C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary, 95kV BIL.
	5	Liquid-immersed, three-phase	750–2500	1500 kVA, 65 °C, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary, 125 kV BIL.
3	6	Dry-type, low-voltage, single-phase	15–333	25 kVA, 150 °C, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL.
4	7	Dry-type, low-voltage, three-phase	15–150	75 kVA, 150 °C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL.
	8	Dry-type, low-voltage, three-phase	225–1000	300 kVA, 150 °C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL.
6	9	Dry-type, medium-voltage, three-phase, 20–45kV BIL.	15–500	300 kVA, 150 °C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL.

TABLE IV.6—ENGINEERING DESIGN LINES (DLS) AND REPRESENTATIVE UNITS FOR ANALYSIS—Continued

EC*	DL	Type of distribution transformer	kVA Range	Representative unit for this engineering design line
	10	Dry-type, medium-voltage, three-phase, 20–45kV BIL.	750–2500	1500 kVA, 150 °C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL.
8	11	Dry-type, medium-voltage, three-phase, 46–95kV BIL.	15–500	300 kVA, 150 °C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL.
	12	Dry-type, medium-voltage, three-phase, 46–95kV BIL.	750–2500	1500 kVA, 150 °C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL.
10	13A	Dry-type, medium-voltage, three-phase, 96–150kV BIL.	75–833	300 kVA, 150 °C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL.
	13B	Dry-type, medium-voltage, three-phase, 96–150kV BIL.	225–2500	2000 kVA, 150 °C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL.

*EC means equipment class (see Chapter 3 of the TSD). DOE did not select any representative units from the single-phase, medium-voltage equipment classes (EC5, EC7 and EC9), but calculated the analytical results for EC5, EC7, and EC9 based on the results for their three-phase counterparts.

3. Design Option Combinations

There are many different combinations of design options that could be considered for each representative unit DOE analyzes. While DOE cannot consider all the possible combinations of design options, DOE attempts to select design option combinations that are common in the industry while also spanning the range of possible efficiencies for a given DL. For each design option combination chosen, DOE evaluates 518 designs based on different A and B factor [26] combinations. For the engineering analysis, DOE reused many of the design option combinations that were analyzed in the previous rulemaking for distribution transformers.

For the preliminary analysis, DOE considered a design option combination that uses an amorphous steel core for each of the dry-type design lines, whereas DOE's previous rulemaking did not consider amorphous steel designs for the dry-type design lines. Instead, DOE had considered H–0 domain refined (H–0 DR) steel as the maximum-technologically feasible design. However, DOE is aware that amorphous steel designs are now used in dry-type distribution transformers. Therefore, DOE considered amorphous steel designs for each of the dry-type transformer design lines in the preliminary analysis.

During preliminary interviews with manufacturers, DOE received comment that it should consider additional design option combinations using aluminum for the primary conductor rather than copper. While manufacturers commented that copper is still used for the primary conductor in many distribution transformers, they noted that aluminum has become relatively more common. This is due to the relative prices of copper and aluminum. In recent years, copper has become even more expensive compared to aluminum.

DOE also noted that certain design lines were lacking a design to bridge the efficiency values between the lowest efficiency amorphous designs and the next highest efficiency designs. In an effort to close that gap for the preliminary analysis, DOE evaluated ZDMH and M2 core steel as the highest efficiency designs below amorphous for the liquid-immersed design lines. Similarly, DOE evaluated H–0 DR and M3 core steel as the highest efficiency designs below amorphous for dry-type design lines.

The joint comments submitted by NPCC and NEEA as well as those submitted by ASAP, ACEEE, and NRDC indicated that DOE should include these supplementary designs in the reference case analysis for the NOPR. (NPCC/NEEA, No. 11 at pp. 5–6; ASAP/ACEEE/NRDC, No. 28 at p. 3) NPCC and NEEA added that DOE should consider all potential design options in its analyses to ensure that all the cost-effective means of reaching higher efficiencies have been considered. (NPCC/NEEA, No. 11 at p. 4) For example, several stakeholders recommended that DOE examine wound core designs for its analysis of dry-type distribution transformers. (NPCC/NEEA, No. 11 at pp. 2, 4–5; EMS, Pub. Mtg. Tr., No. 34 at p. 86; PG&E, Pub. Mtg. Tr., No. 34 at p. 87; ASAP, Pub. Mtg. Tr., No. 34 at p. 88) Joint comments from ASAP, ACEEE, and NRDC and PG&E and SCE noted that DOE should consider wound core designs for its low-voltage dry-type design lines, where high sales volume could better justify the additional equipment and tooling costs of switching to wound core production. (ASAP/ACEEE/NRDC, No. 28 at p. 3; PG&E/SCE, No. 32 at p. 1; PG&E, Pub. Mtg. Tr., No. 34 at p. 261) Lastly, HVOLT noted that wound cores in kVA sizes beyond 300 kVA will tend to buzz, but Hex Tec clarified that the wound cores used in symmetric core designs above 300 kVA do not induce any additional audible sound. (HVOLT, Pub. Mtg. Tr., No. 34 at p. 51; Hex Tec, Pub. Mtg. Tr., No. 34 at p. 51)

DOE clarifies that although it was not done so in the preliminary analysis, DOE has incorporated its supplementary designs into the reference case for the NOPR analysis. Additionally, DOE aims to consider the most popular design option combinations, and the design option combinations that yield the greatest improvements in efficiency. While DOE is unable to consider all potential design option combinations, it does consider multiple designs for each representative unit and has considered additional design options in its NOPR analysis based on stakeholder comments.

As for wound core designs, DOE did consider analyzing them for all of its dry-type representative units that are 300 kVA or less in the NOPR. However, based on limited availability in the United States, DOE did not believe that it was feasible to include these designs in their final engineering results. For similar availability reasons, DOE chose to exclude its wound core ZDMH and M3 designs from its low-voltage dry-type analysis. Based on how uncommon these designs are in the current market, DOE believes that it would be unrealistic to include them in engineering curves without major adjustments.

DOE did not consider wound core designs for DLs 10, 12, and 13B because they are 1500 kVA and larger. DOE understands that conventional wound core designs in these large kVA ratings will emit an audible ''buzzing'' noise, and will experience an efficiency penalty that grows with kVA rating such

[26] A and B factors correspond to loss valuation and are used by DOE to generate distribution transformers with a broad range of performance and design characteristics.

that stacked core is more attractive. DOE notes, however, that it does consider a wound core amorphous design in each of the dry-type design lines.

DOE also received interested party feedback indicating that DOE should consider step-lap miter designs for its dry-type design lines. (NPCC/NEEA, No. 11 at p. 4; Metglas, Pub. Mtg. Tr., No. 34 at p. 91) In the preliminary analysis, DOE had only analyzed fully-mitered designs for the dry-type design lines, but stakeholders noted that step-lap miter designs could potentially yield greater efficiencies than the fully-mitered designs. However, during the negotiations process, interested parties clarified that step-lap mitering may not be cost-effective in the smaller dry-type designs because the smaller average steel piece size gives rise to a larger destruction factor, and larger losses, than would be predicted by modeling. (ONYX, Pub. Mtg. Tr., No. 30 at p. 43) Stakeholders agreed that it would not be appropriate to consider step-lap mitering for design line 6, a 25 kVA unit, to reflect its scarcity or absence from the market. Therefore, in the NOPR DOE analyzed step-lap miter designs for each of the dry-type design lines except design line 6.

In the preliminary analysis, DOE considered several premium grade core steels. It examined H0–DR, ZDMH, and SA1 amorphous core steels in its designs, as well as the standard M-grade steels. DOE requested comment on whether there were other premium grade core steels that should be considered in the analysis. ABB commented that ZDMH, H0–DR, and SA1 amorphous steels cover all the high performance core steel grades that are currently commercially available. (ABB, No. 14 at p. 13) Therefore, DOE continued to analyze them for the NOPR and did not consider any additional premium core steels.

DOE did opt to add two design option combinations that incorporate M-grade steels that have become popular choices at the current standard levels. For all medium-voltage, dry-type design lines (9–13B), DOE added a design option combination of an M4 step-lap mitered core with aluminum primary and secondary windings. For design line 8, DOE added a design option combination of an M6 fully mitered core with aluminum primary and secondary windings. DOE understands both combinations to be prevalent baseline options in the present transformer market.

For the NOPR analysis, DOE also made the decision to remove certain high flux density designs from DL7 in order to be consistent with designs submitted by manufacturers.[27] There is a variety of reasons that manufacturers would choose to limit flux density (*e.g.,* vibration, noise). Further detail on this change can be found in chapter 5 of the TSD.

4. A and B Loss Value Inputs

As discussed, one of the primary inputs to the OPS software is an A and B combination for customer loss evaluation. In the preliminary analysis, DOE generated each transformer design in the engineering analysis based upon an optimized lowest total owning cost evaluation for a given combination of A and B values. Again, the A and B values represent the present value of future core and coil losses, respectively and DOE generated designs for over 500 different A and B value combinations for each of the design option combinations considered in the analysis.

In response to the preliminary analysis, Berman Economics commented that designing a transformer to total owning cost based on A and B factors will result in a higher first cost transformer than a design that aims to minimize first cost for a given efficiency level. (BE, No. 16 at p. 6) Additionally, Berman Economics noted that many utilities and customers do not specify an A and B value when ordering transformers, and will just ask for the lowest first cost design. (BE, Pub. Mtg. Tr., No. 34 at p. 123)

DOE notes that the designs created in the engineering analysis span a range of costs and efficiencies for each design option combination considered in the analysis. This range of costs and efficiencies is determined by the range of A and B factors used to generate the designs. Although DOE does not generate a design for every possible A and B combination, because there are infinite variations, DOE believes that its 500-plus combinations have created a sufficiently broad design space. By using so many A and B factors, DOE is confident that it produces the lowest first cost design for a given efficiency level and also the lowest total owning cost design. Furthermore, although all distribution transformer customers do not purchase based on total owning cost, the A and B combination is still a useful tool that allows DOE to generate a large number of designs across a broad range of efficiencies and costs for a particular design line. Finally, OPS noted at the public meeting that its design software requires A and B values as inputs. (OPS, Pub. Mtg. Tr., No. 34 at p. 123) For all of these reasons, DOE continued to use A and B factors in the NOPR to generate the range of designs for the engineering analysis.

[27] During the negotiations process, DOE's subcontractor, Navigant Consulting, Inc. (Navigant), participated in a bidirectional exchange of engineering data in an effort to validate the OPS designs generated for the engineering analysis.

5. Materials Prices

In distribution transformers, the primary materials costs come from electrical steel used for the core and the aluminum or copper conductor used for the primary and secondary winding. As these are commodities whose prices frequently fluctuate throughout a year and over time, DOE attempted to account for these fluctuations by examining prices over multiple years. For the preliminary analysis, DOE conducted the engineering analysis analyzing materials price information over a five-year time period from 2006–2010, all in constant 2010$. Whereas DOE used a five-year average price in the previous rulemaking for distribution transformers, for the preliminary analysis in this rulemaking, DOE selected one year from its five-year time frame as its reference case, namely 2010. Additionally, DOE considered high and low materials price sensitivities from that same five-year time frame, 2008 and 2006 respectively.

DOE decided to use current (2010) materials prices in its analysis for the preliminary analysis because of feedback from manufacturers during interviews. Manufacturers noted the difficulty in choosing a price that accurately projects future materials prices due to the recent variability in these prices. Manufacturers also commented that the previous five years had seen steep increases in materials prices through 2008, after which prices declined as a result of the global economic recession. Further detail on these factors can be found in appendix 3A. Due to the variability in materials prices over this five-year timeframe, manufacturers did not believe a five-year average price would be the best indicator, and recommended using the current materials prices.

To estimate its materials prices, DOE spoke with manufacturers, suppliers, and industry experts to determine the prices paid for each raw material used in a distribution transformer in each of the five years between 2006 and 2010. While prices fluctuate during the year and can vary from manufacturer to manufacturer depending on a number of variables, such as the purchase quantity, DOE attempted to develop an average materials price for the year based on the price a medium to large manufacturer would pay.

In general, stakeholders agreed with DOE's approach for analyzing materials prices in the preliminary analysis. Power Partners and EEI agreed with DOE's approach of using 2010 materials prices in the reference case and examining alternate years' materials prices as sensitivities. (PP, Pub. Mtg. Tr., No. 34 at p. 100; EEI, Pub. Mtg. Tr., No. 34 at p. 100) Howard Industries noted that 2010 prices are reasonable for the reference case as long as DOE uses the 2010 prices with any additional design runs. (HI, No. 23 at p. 6) Similarly, ABB agreed with DOE's approach to use a single reference year, such as 2010, for the materials prices, and noted that materials prices are reaching an all-time high in 2011. (ABB, No. 14 at p. 14) Finally, Power Partners commented that DOE did a reasonable job grouping the various wire sizes into ranges. (PP, Pub. Mtg. Tr., No. 34 at p. 118)

Conversely, Southern Company and FPT commented that DOE's approach for generating reference case materials prices could be improved. Southern Company noted that 2010 materials prices may be lower than future materials prices once the economy improves and there is a limited availability of supplies coupled with increased demand. (SC, No. 22 at p. 4) FPT also commented that DOE should consider whether there will be an adequate supply of higher grade core steels at the price points identified in the analysis, noting that smaller manufacturers are likely not able to purchase materials at the same price points as larger manufacturers and may have to pay more, especially if there is an increase in demand resulting from amended standards. (FPT, No. 27 at p. 2)

With the onset of the negotiations, DOE was presented with an opportunity to implement a 2011 materials price case based on data it had gathered before and during the negotiation proceedings. Relative to the 2010 case, the 2011 prices were lower for all steels, particularly M2 and lower grade steels.

For the NOPR, DOE continued to use the 2010 materials prices as a reference case scenario, but added a second, 2011 price case. DOE presents both cases as recent examples of how the steel market fluctuates and uses both to derive economic results. It also considered high and low price scenarios based on the 2008 and 2006 materials prices, respectively, but adjusted the prices in each of these years to consider greater diversity in materials prices. For the high price scenario, DOE increased the 2008 prices by 25 percent, and for the low price scenario, DOE decreased the 2006 prices by 25 percent as additional sensitivity analyses. DOE believes that these price sensitivities accurately account for any pricing discrepancies experienced by smaller or larger manufacturers, and adequately consider potential price fluctuations.

NPCC and NEEA jointly commented that DOE should forecast future materials prices based on spot commodities future prices. (NPCC/NEEA, No. 11 at pp. 6–7) Similarly, FPT commented that 2010 materials prices may not be a good indication of future steel prices, which will likely increase. (FPT, No. 27 at p. 12) On the other hand, Berman Economics commented that the pricing of core steels over the past few years has declined, even though standard levels have shifted the market to higher core steel grades. As a result, Berman Economics stated that core steel production could be expected to expand in light of new energy conservation standards without any significant impacts on the materials prices. (BE, No. 16 at p. 10)

For the engineering analysis, DOE did not attempt to forecast future materials prices. DOE continued to use the 2010 materials price in the reference case scenario, added a 2011 reference scenario, and also considered high and low sensitivities to account for any potential fluctuations in materials prices. The LCC and NIA consider a scenario, however, in which transformer prices increase in the future based on increasing materials prices, among other variables. Further detail on this scenario can be found in chapter 8 of the TSD.

Several stakeholders commented that the average materials prices DOE calculated for the 2006–2010 timeframe, particularly for year 2010, were not accurate. NEMA recommended that DOE gather additional information from manufacturers on this topic. (NEMA, No. 13 at p. 6) FPT commented that DOE's price of $2.38 per pound for amorphous steel appeared to be low, and questioned whether the price had been verified with suppliers of amorphous material. Joint comments submitted by ASAP, ACEEE, and NRDC stated that DOE's materials prices were too high compared to market prices in 2010. (ASAP/ACEEE/NRDC, No. 28 at p. 2) HVOLT commented that DOE's prices for copper and aluminum were understated, noting that current copper prices are around $6.50. (HVOLT, No. 33 at p. 1; HVOLT, Pub. Mtg. Tr., No. 34 at p. 117) Power Partners commented that the prices for aluminum wire were too high and that prices for copper wire were too low, suggesting that DOE derive its conductor prices by adding a processing cost to the COMEX or London Metal Exchange (LME) indices. (PP, Pub. Mtg. Tr., No. 34 at pp. 100, 118; PP, No. 19 at p. 3) To this point, Hex Tec added that the fabrication cost varies by wire size. (HEX, Pub. Mtg. Tr., No. 34 at p. 118)

For the NOPR, DOE reviewed its materials prices during interviews with manufacturers and industry experts and revised its materials prices for copper and aluminum conductors. As suggested by Power Partners, DOE derived these prices by adding a processing cost increment to the underlying index price. DOE determined the current 2011 index price from the LME and COMEX. These indices only had current 2011 values available, so DOE used the producer price index for copper and aluminum to convert the 2011 index price into prices for the time period of 2006–2010. DOE then applied a unique processing cost adder to the index price for each of its conductor groupings. To derive the adder price, DOE compared the difference in the LME index price to the 2011 price paid by manufacturers, and applied this difference to the index price in each year. DOE inquired with many manufacturers, both large and small, to derive these prices. Further detail can be found in chapter 5 of the TSD.

DOE reviewed core steel prices with manufacturers and industry experts and found them to be accurate within the range of prices paid by manufacturers in 2010. However, based on feedback in negotiations, DOE adjusted steel prices for M4 grade steels and lower grade steels.

As for FPT's concern regarding prefabricated amorphous cores, estimated at $2.38 per pound in 2010, DOE notes that this price was derived from speaking with several North American suppliers of prefabricated amorphous cores, and aligns with marked-up price estimates for raw amorphous ribbon. Therefore, so DOE continued to use this price estimate in the NOPR for the 2010 price scenario.

6. Markups

DOE derived the manufacturer's selling price for each design in the engineering analysis by considering the full range of production costs and non-production costs. The full production cost is a combination of direct labor, direct materials, and overhead. The overhead contributing to full production cost includes indirect labor, indirect material, maintenance, depreciation, taxes, and insurance related to company assets. Non-production cost includes the cost of selling, general and administrative items (market research, advertising, sales representatives, and logistics), research and development (R&D), interest payments, warranty and risk provisions, shipping, and profit factor. Because profit factor is included in the non-production cost, the sum of production and non-production costs is an estimate of the manufacturer's selling price. DOE utilized various markups to arrive at the total cost for each component of the distribution transformer. These markups are outlined in greater detail in chapter 5 of the TSD.

NPCC and NEEA jointly commented that DOE should vet the non-production markup with manufacturers to ensure that it is accurate. (NPCC/NEEA, No. 11 at p. 6) Berman Economics added that manufacturers do not price their units in the same way that DOE did in its analysis; rather, they look at their costs and the market and generate a competitive price accordingly. Therefore, Berman Economics suggested that DOE only look at the material and labor costs and refrain from including the other markups. (BE, Pub. Mtg. Tr., No. 34 at p. 96)

DOE interviewed manufacturers of distribution transformers and related products to learn about markups, among other topics, and observed a number of very different practices. In absence of a consensus, DOE attempted to adapt manufacturer feedback to inform its current modeling methodology while acknowledging that it may not reflect the exact methodology of many manufacturers. DOE feels that it is necessary to model markups, however, since there are costs other than material and labor that affect final manufacturer selling price. The following sections describe various facets of DOE's markups for distribution transformers.

a. Factory Overhead

DOE uses a factory overhead markup to account for all indirect costs associated with production, indirect materials and energy use (*e.g.,* annealing furnaces), taxes, and insurance. In the preliminary analysis, DOE derived the cost for factory overhead by applying a 12.5 percent markup to direct material production costs.

Several stakeholders commented that factory overhead is more commonly estimated as a markup on labor costs, not material costs. (NPCC/NEEA, No. 11 at pp. 2, 6; ASAP/ACEEE/NRDC, No. 28 at p. 2; PP, Pub. Mtg. Tr., No. 34 at p. 102; HEX, Pub. Mtg. Tr., No. 34 at p. 103) ABB commented that factory overhead should not be tied to direct material costs, but rather to the design option being produced and the volume being produced, using a fixed quantity for factory overhead based on the design option. (ABB, No. 14 at pp. 14–15)

DOE appreciates the comments and considered other approaches for calculating factory overhead for the NOPR. However, DOE was unable to determine an alternate methodology that could accurately estimate factory overhead costs. In the absence of further information for how to calculate factory overhead based on labor costs or design options, DOE continued to use its approach based on the material production costs. DOE notes that factory overhead costs are not applied to the material production cost component, but are simply estimated based on the production costs.

In the preliminary analysis, DOE applied the same factory overhead markup to its prefabricated amorphous cores as it did to its other design options where the manufacturer was assumed to produce the core. Since the factory overhead markup accounts for indirect production costs that are not easily tied to a particular design, it was applied consistently across all design types. DOE did not find that there was sufficient substantiation to conclude that manufacturers would apply a reduced overhead markup for a design with a prefabricated core.

Hammond Power Systems and Howard Industries agreed with DOE's decision to apply the same factory overhead to prefabricated amorphous cores. (HPS, No. 3 at p. 4; HI, No. 23 at p. 6) On the other hand, NPCC and NEEA jointly commented that factory overhead should not be applied to prefabricated cores because the markup would already be included in the selling price of the prefabricated core. (NPCC/NEEA, No. 11 at p. 7) ABB, however, noted that even though manufacturers may outsource various components of the transformer manufacturing, such as enclosures, cores, or coils, DOE should assume a vertical manufacturing process in which the manufacturer produces all components in-house. (ABB, No. 14 at pp. 14–15) NEMA commented that DOE should gather additional data from individual manufacturers on the topic of factory overhead. (NEMA, No. 13 at p. 6)

For the NOPR analysis, DOE continued to apply the same factory overhead markup to prefabricated amorphous cores as to other cores built in-house. This approach is consistent with the suggestion of the manufacturers, and DOE notes that factory overhead for a given design applies to many items aside from the core production. Furthermore, since DOE already accounts for decreased labor hours in its designs using prefabricated amorphous cores, but also considers an increased core price based on a prefabricated core rather than the raw amorphous material, it already accounts for the tradeoffs associated with developing the core in-house versus outsourced.

During negotiations, DOE learned from both manufacturers of transformers and manufacturers of transformer cores that mitering and, to a greater extent, step-lap mitering, result in a per-pound cost of finished cores higher than butt-lapped units built to the same specifications. (ONYX, Pub. Mtg. Tr., No. 30 at p. 43) This helps to account for the fact that butt-lapping is common at baseline efficiencies in today's low-voltage market.

In response, DOE opted to increase mitering costs for both low- and medium-voltage dry-type designs. In the medium-voltage case, DOE incorporated a processing cost of 10 cents per core pound for step-lap mitering. In the low-voltage case, DOE incorporated a processing cost of 10 cents per core pound for ordinary mitering and 20 cents per core pound for step-lap mitering. DOE used different per pound adders for step-lap mitering for medium-voltage and low-voltage units because the base case design option for each is different. For low-voltage units, DOE modeled butt-lapped designs at the baseline efficiency level whereas ordinary mitering was modeled at the baseline for medium-voltage. Therefore, using a step-lap mitered core represents a more significant change in technology for low-voltage dry-type transformers and thus the higher markup.

b. Labor Costs

In the preliminary analysis, DOE accounted for additional labor and material costs for large (≥1500 kVA), dry-type designs using amorphous metal. The additional labor costs accounted for special handling considerations, since the amorphous material is very thin and can be difficult to work with in such a large core. They also accounted for extra bracing that is necessary for large, wound core, dry-type designs in order to prevent short circuit problems.

NPCC, NEEA, and NEMA commented that DOE should consult individual manufacturers to gather information about the additional costs DOE associates with large amorphous designs. (NPCC/NEEA, No. 11 at p. 6; NEMA, No. 13 at p. 6) NPCC and NEEA added that DOE should consider a range of assumed incremental costs starting at zero when analyzing amorphous core designs. (NPCC/NEEA, No. 11 at p. 7)

Several manufacturers also commented on the issue of additional costs for large amorphous designs. Howard Industries commented that these designs face similar cost increases as those that DOE identified for large dry-type designs using an amorphous core. It noted that typically these liquid-immersed designs require an additional 10 hours of handling, added cost for the epoxy and catalyst used in sealing the amorphous cores, and additional bracing depending on the weight of the core/coil assembly. Howard Industries estimated this cost as an extra $100 to $200 for additional materials and hardware. (HI, No. 23 at p. 6)

ABB commented that if DOE accounts for additional labor and material costs for large amorphous designs, then it should apply the same logic to all design options, and also noted that large liquid-immersed amorphous designs would have the same costs as the dry-type designs. ABB noted that large wound cores would have more labor and hardware compared to small wound cores, and that stacked cores will have more labor than wound cores. Finally, ABB noted that stacked M2 would require more labor than stacked M6 steel. (ABB, No. 14 at p. 15) Power Partners commented that DOE needed to add in additional assembly time for liquid-immersed transformers using amorphous cores. (PP, Pub. Mtg. Tr., No. 34 at p. 102) Finally, Hex Tec noted that certain core construction methods (*e.g.,* symmetric core designs) make the handling of amorphous material much easier, which can eliminate the need for extra handling. (HEX, Pub. Mtg. Tr., No. 34 at p. 103)

During negotiations, Federal Pacific commented that it believed DOE was underestimating labor hours for core assembly for all low- and medium-voltage dry-type design lines.

In response to interested party feedback, DOE applied an incremental increase in core assembly time to amorphous designs in the liquid-immersed design line 5 (1500 kVA). This additional core assembly time of 10 hours is consistent with DOE's treatment of amorphous designs in large, dry-type design lines. However, DOE did not account for additional hardware costs for bracing in the liquid-immersed designs using amorphous cores. This is because DOE already accounts for bracing costs for all of its liquid-immersed designs, which use wound cores, in its analysis. DOE determined that it adequately accounted for these bracing costs in the smaller kVA sizes using amorphous designs, and thus only made the change to the large (≥1500 kVA) design lines. DOE did not model varying incremental cost increases starting with zero for large amorphous designs, as NEEA and NPCC suggested, noting that the impact of these incremental costs are oftentimes very minor for large, expensive transformer designs. In response to Federal Pacific's comment and data from other manufacturers of medium- and low-voltage transformers, DOE explored its estimates of labor hours and increased those relating to core assembly for design lines 6–13B. Details on the specific values of the adjustments can be found in chapter 5 of the TSD.

Finally, in response to ABB's comment that DOE should apply different labor and material costs to each design option in the analysis, DOE notes that it already does account for costs differently based on the design options used. Labor requirements are, for example, determined in part based on the grade of core steel, the core weight, and the number of turns in the winding. Similarly, material costs are determined specific to each material input based on each design's specifications.

c. Shipping Costs

During its interviews with manufacturers in the preliminary analysis, DOE was informed that manufacturers often pay shipping (freight) costs to the customer. Manufacturers indicated that they absorb the cost of shipping the units to the customer and that they include these costs in their total cost structure when calculating profit markups. As such, manufacturers apply a profit markup to their shipping costs just like any other cost of their production process. Manufacturers indicated that these costs typically amount to anywhere from four to eight percent of revenue.

In the previous rulemaking for distribution transformers, DOE accounted for shipping costs exclusively in the LCC analysis. These costs were paid by the customer, and thus did not include a markup from the manufacturer based on its profit factor. In the preliminary analysis, DOE included shipping costs in the manufacturer's cost structure, which is then marked up by a profit factor. These shipping costs account for delivering the units to the customer, who may then bear additional shipping costs to deliver the units to the final end-use location. As such, DOE accounts for the first leg of shipping costs in the engineering analysis and then any subsequent shipping costs in the LCC analysis. The shipping cost was estimated to be $0.22 per pound of the transformer's total weight and typically amounts to four to eight percent of the total MSP. DOE derived the $0.22 per pound by relying on the shipping costs developed in its previous rulemaking on distribution transformers, when DOE collected a sample of shipping quotations for transporting transformers. In that rulemaking, DOE estimated shipping costs as $0.20 per pound based on an average shipping distance of 1,000 miles. For the preliminary analysis, DOE updated the cost to $0.22 per pound based on the price index for freight shipping between 2007 and 2010. Additional detail on these shipping costs can be found in chapter 5 and chapter 8 of the TSD.

DOE received several comments about the methodology for deriving shipping costs. NEMA commented that DOE should gather additional information from manufacturers. (NEMA, No. 13 at p. 6) Federal Pacific commented that weight increases as transformers become more efficient, and noted that shipping costs would thus increase if standards were amended. (FPT, No. 27 at pp. 4–5) Several stakeholders commented that DOE should consider the cost of fuel in its shipping cost calculation, particularly since it has increased in recent years. (NRECA/T&DEC, No. 31 and 36 at p. 3; EEI, Pub. Mtg. Tr., No. 34 at p. 95; EEI, No. 29 at p. 5) NPCC and NEEA jointly commented that shipping costs will increase with time as diesel fuel prices rise. (NPCC/NEEA, No. 11 at p. 7)

For the NOPR, DOE revised its shipping cost estimate to account for the rising cost of diesel fuel. DOE adjusted its previous shipping cost of $0.20 (in 2006 dollars) from the previous rulemaking to a 2011 cost based on the producer price index for No. 2 diesel fuel. This yielded a shipping cost of $0.28 per pound. DOE also retained its shipping cost calculation based on the weight of the transformer to differentiate the shipping costs between lighter and heavier, typically more efficient, designs.

In the preliminary analysis, DOE applied a non-production markup to all cost components, including shipping costs, to derive the MSP. DOE based this cost treatment on the assumption that manufacturers would mark up the shipping costs when calculating their final selling price. The resulting shipping costs were, as stated, approximately four to eight percent of total MSP.

During the public meeting, ASAP asked if DOE had found market data that indicated that shipping costs should be included in the sale price. (ASAP, Pub. Mtg. Tr., No. 34 at p. 102) HPS commented that DOE's assumption that shipping costs are typically four to eight percent of MSP is accurate, but noted that it does not typically mark up shipping costs. (HPS, No. 3 at p. 5) ABB commented that shipping costs are recognized as an expense to manufacturers, but that they do not impact the profit markup of the manufacturer because transformers must be priced based on the market. Rather, shipping costs reduce the profit of the sale. Additionally, ABB noted that shipping costs are typically only two to four percent of total transformer costs. (ABB, No. 14 at p. 15) Similarly, Federal Pacific commented that manufacturers bear the cost of shipping, but they do not mark up the shipping cost in their profit markup or other markups. (FPT, No. 27 at p. 17) Conversely, Howard Industries agreed with DOE's approach in which markups were applied to the cost of shipping. Howard Industries added that it agreed that shipping costs are typically four to eight percent of revenues. (HI, No. 23 at p. 6)

Based on the comments received and DOE's additional research into the treatment of shipping costs through manufacturer interviews, DOE has preliminarily decided to retain the shipping costs in its calculation of MSP, but not to apply any markups to the shipping cost component. Therefore, shipping costs were added separately into the MSP calculation, but not included in the cost basis for the non-production markup. The resulting shipping costs were still in line with the estimate of four to eight percent of MSP for all the dry-type design lines. For the liquid-immersed design lines, the shipping costs ranged from six to twelve percent of MSP and averaged about nine percent of MSP.

7. Baseline Efficiency and Efficiency Levels

DOE analyzed designs over a range of efficiency values for each representative unit. Within the efficiency range, DOE developed designs that approximate a continuous function of efficiency. However, DOE only analyzes incremental impacts of increased efficiency by comparing discrete efficiency benchmarks to a baseline efficiency level. The baseline efficiency level evaluated for each representative unit is the existing energy conservation standard level of efficiency for distribution transformers established either in DOE's previous rulemaking or by EPACT 2005. The incrementally higher efficiency benchmarks are referred to as "efficiency levels" (ELs) and, along with MSP values, characterize the cost-efficiency relationship above the baseline. These ELs are ultimately used by DOE if it decides to amend the existing energy conservation standards.

For the NOPR, DOE considered several criteria when setting ELs. First, DOE harmonized the efficiency values across single-phase transformers and the per-phase kVA equivalent three-phase transformers. For example, a 50 kVA single-phase transformer would have the same efficiency requirement as a 150 kVA three-phase transformer. This approach is consistent with DOE's methodology from the previous rulemaking and from the preliminary analysis of this rulemaking. Therefore, DOE selected equivalent ELs for several of the representative units that have equivalent per-phase kVA ratings.

Second, DOE selected equally spaced ELs by dividing the entire efficiency range into five to seven evenly spaced increments. The number of increments depended on the size of the efficiency range. This allowed DOE to examine impacts based on an appropriate resolution of efficiency for each representative unit.

Finally, DOE adjusted the position of some of the equally spaced ELs and examined additional ELs. These minor adjustments to the equally spaced ELs allowed DOE to consider important efficiency values based on the results of the software designs. For example, DOE adjusted some ELs slightly up or down in efficiency to consider the maximum efficiency potential of non-amorphous design options. Other ELs were added to consider important benchmark efficiencies, such as the NEMA Premium efficiency levels for LVDT distribution transformers. Last, DOE considered additional ELs to characterize the maximum-technologically feasible design for representative units where the harmonized per-phase efficiency value would have been unachievable for one of the representative units.

EEI requested that DOE provide summary tables of the ELs and the proposed TSLs to highlight any differences between the two. (EEI, Pub. Mtg. Tr., No. 34 at p. 125) Furthermore, EEI pointed out that CSL 0 is TSL 3 or 4 from the last rulemaking and is more efficient than a 2005 or 2007 unit. (EEI, Pub. Mtg. Tr., No. 34 at p. 113)

NEMA recommended that the TSLs from the previous rulemaking be visually overlaid with the ELs from this rulemaking to allow easier comparisons between the recent standards and the current rulemaking. (NEMA, No. 13 at pp. 6–7)

Schneider Electric commented that it would like to see the label "CSL 0" removed from the analysis and instead replaced with exactly what those levels were and where it was mandated, *i.e.,* in EISA 2007. (SE., Pub. Mtg. Tr., No. 34 at p. 119)

DOE has found that multiple sets of efficiency levels and candidate standard levels have confused stakeholders in the past, and prefers to limit this document's discussion to those ELs at hand. EEI is correct to point out that the previous rule's standard is the current rule's baseline. DOE is statutorily prohibited from decreasing efficiency standards, and so any discussion of future standards necessarily begins with what is in effect at the time.

Berman Economics noted that high-cost designs that are above the minimum first cost amount for a given EL should not be considered in DOE's analysis because they do not represent the cost required to comply with the standard. It felt that, by including these designs, DOE artificially increases the cost estimate from the Monte Carlo analysis. (BE, No. 16 at pp. 6–7)

Although DOE's current test procedure specifies a load value at which to test transformers, DOE recognizes that different consumers see real-world loadings that may be higher or lower. In those cases, consumers may choose a transformer offering a lower LCC even when faced with a higher first cost. If DOE's cost/efficiency design cloud were redrawn to reflect loadings other than those specified in the test procedure, different designs would migrate to the optimum frontier of the cloud. Additionally, although DOE's engineering analysis reflects a range of transformers costs for a given EL, the LCC analysis only selects transformer designs near the lowest cost point.

8. Scaling Methodology

For the preliminary analysis, DOE performed a detailed analysis on each representative unit and then extrapolated the results of its analysis from the unit studied to the other kVA ratings within that same engineering design line. DOE performed this extrapolation to develop inputs to the national impacts analysis. The technique it used to extrapolate the findings of the representative unit to the other kVA ratings within a design line is referred to as "the 0.75 scaling rule." This rule states that, for similarly designed transformers, costs of construction and losses scale with the ratio of their kVA ratings raised to the 0.75 power. The relationship is valid where the optimum efficiency loading points of the two transformers being scaled are the same. DOE used the same methodology to scale its findings during the previous rulemaking on distribution transformers.

In response to the preliminary analysis, DOE received multiple comments regarding the 0.75 scaling rule. HVOLT expressed its support for the use of the 0.75 scaling rule. (HVOLT, Pub. Mtg. Tr., No. 34 at p. 139) Several other stakeholders stated that they believed the 0.75 scaling rule is accurate over small kVA ranges, but can break down near the limits of the scaling range. (HPS, No. 3 at p.4; NPCC/NEEA, No. 11 at pp. 7–8; NEMA, No. 13 at pp. 4, 6; SE., No. 18 at p.7; HI, No. 23 at p. 7; FPT, Pub. Mtg. Tr., No. 34 at p. 137) NPCC, NEEA and NEMA recommended that DOE consider analyzing additional design lines and representative units to maintain the integrity of the scaling. (NPCC/NEEA, No. 11 at pp. 7–8; NEMA, No. 13 at pp. 4–6) FPT also suggested introducing additional designs to the analysis, noting that it has found it difficult to meet the efficiency levels on the lower-end kVAs for the dry-types. (FPT, Pub. Mtg. Tr., No. 34 at p. 136) Schneider Electric recommended that DOE expand its kVA ranges within the design lines and overlay the design lines to allow for multiple evaluation points within the scaling rule. (SE., No. 18 at p. 7) Howard Industries believed that DOE should adjust the 0.75 scaling factor to account for more efficient and costlier materials needed to stay within the size and weight constraints of customers' demands. (HI, No. 23 at p. 7)

EEI commented that the 0.75 scaling rule may not be accurate for scaling outside a single standard deviation of kVA size. EEI recommended that DOE work with manufacturers to create new formulas for scaling beyond a single standard deviation. (EEI, No. 29 at p. 6) Warner Power stated that the 0.75 scaling rule is less accurate for higher scaling ratios where transformer designs change significantly, but felt that the rule was accurate for scaling where the ratio of kVAs was between 0.8 and 1.2. (WP, No. 30 at pp. 7, 11)

ABB noted that the 0.75 scaling rule is accurate within about a half order of magnitude when all other parameters are constant. ABB also stated that in their experience the 0.75 coefficient increases as the kVA decreases and approaches 1.0 as an upper limit. ABB added that the same is true as the BIL increases. (ABB, No. 14 at pp. 10, 13) Hammond agreed that the 0.75 scaling rule can be problematic for smaller kVAs of higher voltage and BIL ratings. (HPS, No. 3 at p. 4) Metglas explained that the scaling rule assumes one has the same percentage insulation in the cross-section of the conductor in the transformers while, in reality, as the transformers get smaller, more insulation is needed to maintain the same BIL. FPT believed that the 0.75 scaling rule was less accurate for lower kVA ratings (below 500 kVA), in part because small kVA sizes require very small wires that are dramatically more expensive than larger wires in larger kVA sizes. FPT also claimed that current standards are more difficult to meet at the lower kVA sizes. (FPT, No. 27 at pp. 14–17)

PP expressed frustration that the design work involved extrapolating from a 500 kVA model to a 833 kVA model and believed that the extrapolations did not hold true. (PP, Pub. Mtg. Tr., No. 34 at p. 135)

Because it is not practical to directly analyze every combination of design options and kVAs under the rulemaking's scope of coverage, DOE selected a smaller number of units it believed to be representative of the larger scope. Many of the current design lines use representative units retained from the 2007 rulemaking with minor modifications. To generate efficiency values for kVA values not directly analyzed, DOE employed a scaling methodology based on physical principles (overviewed in Appendix 5B) and widely used by industry in various forms. DOE's scaling methodology is an approximation and, as with any approximation, can suffer in accuracy as it is extended further from its reference value.

Several of the comments on this topic suggest that DOE could improve the accuracy of its scaling by limiting the range over which it is applied. To that end, DOE has added a design line (13A to address the case of high BIL, small kVA medium-voltage dry-type units while redesignating the former 13 ''13B''.) DOE will seek to corroborate scaling results with direct analysis in other areas that fall outside of the scaling ranges put forth by commenters for the final rule.

Additionally, DOE modified the way it splices extrapolations from each representative unit to cover equipment classes at large. Previously, DOE extrapolated curves from individual data points and blended them near the boundaries to set standards. Currently, DOE fits a single curve through all available data points in a space and believes that the resulting curve will both be smoother and offer a more robust scaling behavior over the covered kVA range.

Finally, although the laws of physics applied to an ideal transformer yield a scaling exponent of 0.75, DOE recognizes that real-world engineering considerations may produce a behavior better modeled using a different exponent. A number of commenters suggested that the smaller transformers in particular had difficulty meeting standards, which seems to imply that the overall shape of the efficiency curve should come from a lower overall exponent. This would tend to project lower efficiencies at lower kVAs and higher efficiencies at higher kVAs. DOE seeks to further understand how kVA rating and other factors combine to affect transformer efficiency, and seeks comment to that end.

Negotiating parties agreed that deriving results for the ''high'' and ''low'' BIL MVDT equipment classes, namely, 5,6,9, and 10, was the most appropriate way to correctly establish relative standards such that the various efficiencies were logical with respect to each other. (ASAP, Pub. Mtg. Tr., No. ## (docket number unavailable) at p. 175) Parties agreed that standards should be set by adding 10 percent in losses to equipment classes 7 and 8 to derive standards for equipment classes 9 and 10 and subtracting 10 percent in losses from classes 7 and 8 to derive standards for classes 5 and 6. DOE's own analysis suggests that this method of scaling is reasonable and proposes using it to derive standards as it does it today's notice.

Furthermore, several parties noted that liquid-immersed transformers experienced smaller, but not insignificant, performance benefits or penalties as a function of BIL and noted that standards for liquid-immersed units could be tweaked in the same manner as those from MVDT units. Doing so would permit capture of increased energy savings at the more-efficient BILs while still permitting manufacture of the higher BIL transformers at reasonable expense.

DOE requests comment on scaling across both BIL and kVA ratings as it applies to both dry-type and liquid-immersed transformers and on specific ways for DOE to establish a sound methodology for deriving BIL adjustment factors in the liquid-immersed case. DOE also requests comment on how standards are best harmonized across phase counts for all types of transformers and how standards for single-phase transformers may be scaled to produce those of three-phase transformers and vice-versa.

9. Material Availability

DOE received several comments expressing concern over the availability of materials, including core steel and conductors, needed to build energy efficient distribution transformers.

These issues pertain to a global scarcity of materials as well as issues of materials access for small manufacturers.

NPCC, NEEA, Schneider Electric, and the joint comments from ASAP, ACEEE and NRDC all indicated that DOE should revise its selling prices to make sure they are in line with market prices. They commented that DOE's selling prices were too high compared to the prices supplied by manufacturers at the public meeting. (NPCC/NEEA, No. 11 at p. 2 and pp. 6–7; SE., No. 18 at p. 8; ASAP/ACEEE/NRDC, No. 28 at pp. 1–2) The ASAP, ACEEE and NRDC joint comments further specified that commenters at the meeting noted that the price of a small purchase quantity going through a distributor was still 40–60% lower than DOE's price estimates. They added that, if DOE is unable to determine how to adjust its cost inputs, it should apply an adjustment factor to the final selling price to bring it in line with current market prices. If DOE cannot determine prices for LVDT, the joint commenters recommended that DOE apply the adjustment factor from the liquid-immersed analysis to the dry-type analysis. (ASAP/ACEEE/NRDC, No. 28 at pp. 1–2)

Conversely, HVolt, Inc. commented that DOE's finished transformer prices are too low and that several manufacturers have generated selling prices (using current materials prices and low markups) that are 2.5–4 times higher than DOE's prices at CSL 6. (HVOLT, No. 33 at p. 1)

Manufacturers often accuse DOE or over-representing manufacturer selling prices, while parties interested in increasing energy efficiency accuse it of under-representing these prices. DOE is interested in tailoring its analysis to align more closely with the market and believes the best way for parties to demonstrate falsely high or low prices is to submit actual purchase or bid records for designs close to DOE's representative units. If needed, such records could be submitted under the terms of a non-disclosure agreement. Finally, DOE notes that it is the incremental, and not absolute, cost of added efficiency that dominates the cost-effectiveness calculations that it performs. Consequently, errors in the absolute prices will have a smaller effect on the rule outcome than errors in the cost of marginal efficiency. DOE requests further comment on manufacturer selling price and any accompanying data that can help substantiate such comment.

Southern Company commented that DOE should consider the limited supply of amorphous steel when evaluating amended standard levels. It added that there is not enough amorphous steel to meet the demand of the entire transformer industry, and noted that prices for amorphous steel could increase substantially if it was the sole core material used in distribution transformer designs. (SC, No. 22 at p. 1)

DOE is aware that many core steels, including amorphous steels, have constraints on their supply and presents an analysis of global steel supply in Appendix 3–A.

10. Primary Voltage Sensitivities

DOE understands that primary voltage and the accompanying BIL may increasingly affect efficiency of liquid-immersed transformers as standards rise. DOE may conduct primary voltage sensitivity analysis in order to better quantify the effects of BIL and primary voltage on efficiency, and may use such information to consider establishing equipment classes by BIL rating for liquid-immersed distribution transformers.

11. Impedance

In the preliminary analysis, DOE only considered transformer designs with impedances within the normal impedance ranges specified in Table 1 and Table 2 of 10 CFR part 431.192. These impedances represent the typical range of impedance that is used for a given liquid-immersed or dry-type transformer based on its kVA rating and whether it is single-phase or three-phase.

Commonwealth Edison (ComEd) commented that its single-phase overhead transformer specification only allows impedances between 5.3 and 6.2 percent for 250, 333, and 500 kVA transformers. Furthermore, ComEd commented that manufacturers are already having difficulty creating designs with the minimum impedance requirement of 5.3 percent based on the current standard level. (ComEd, No. 24 at p. 3) Similarly, Central Moloney commented that it also has limitations on the impedance of the transformers, which get harder to meet at larger sizes. (Central Moloney, Pub. Mtg. Tr., No. 34 at p. 78)

For the NOPR, DOE continued to consider designs within the normal impedance ranges used in the preliminary analysis. While certain applications may have specifications that are more stringent than these normal impedance ranges, DOE believes that the majority of applications are able to tolerate impedances within these ranges. Since DOE considers a wide array of designs within the normal impedance ranges, it adequately considers the cost considerations of higher and lower impedance tolerances.

DOE requests comment on impedance values and on any related parameters (*e.g.,* inrush current, X/R ratio) that may be used in evaluation of distribution transformers. DOE requests particular comment on how any of those parameters may be affected by energy conservation standards of today's proposed levels or higher.

12. Size and Weight

In the preliminary analysis, DOE did not constrain the weight of its designs. DOE accounted for the full weight of each design generated by the optimization software based on its materials and hardware. Similarly, DOE let several dimensional measurements of its designs vary based on the optimal core/coil dimensions plus space factors. However, DOE did hold certain tank and enclosure dimensions constant for its design lines. Most notably, DOE fixed the height dimension on all of its rectangular tank transformers. For each design that had variable dimensions, DOE accounted for the additional cost of installing the unit, where applicable.

Several interested parties expressed concerns about the size and weight of the designs used in DOE's analysis. Power Partners commented that single-phase liquid-immersed units above 500 kVA are very difficult to design for the current standard level when accounting for the weight and size constraints that users specify. (PP, Pub. Mtg. Tr., No. 34 at p. 46) Power Partners and Howard Industries commented that this issue is particularly a concern for pole-mounted transformers, and noted that many customers put large (500 kVA single-phase) units on poles. (PP, Pub. Mtg. Tr., No. 34 at p. 75; HI, Pub. Mtg. Tr., No. 34 at p. 77) Pepco Holdings, Inc. (PHI) stated that the largest transformer that it will hang on a pole is 333 kVA, but noted that it, too, has concerns about weight and size. (PHI, Pub. Mtg. Tr., No. 34 at p. 77)

Many stakeholders noted that size and weight limitations exist for certain customer specifications. Power Partners, Central Moloney (CM), and PHI all commented that restrictions exist for size and weight, and stated that DOE should account for maximum weight and dimensional limits. (PP, Pub. Mtg. Tr., No. 34 at p. 73; CM, Pub. Mtg. Tr., No. 34 at p. 77; PHI, Pub. Mtg. Tr., No. 34 at p. 74) PHI noted that these restrictions are especially important for pole-mount, subway, subsurface, and network transformers. (PHI, No. 26 and 37 at p. 1) Power Partners commented that over 80 percent of new transformers manufactured are for replacement, and noted that replacement pole-mount transformers need to fit into the existing pole space. As such, Power Partners suggested a maximum weight of 650 pounds for the representative unit in DL2 (25 kVA single-phase) and a maximum weight of 3,600 pounds for the representative unit in DL3 (500 kVA single-phase). (PP, No. 19 at p. 3) Conversely, PG&E commented that the large transformers in its service area are typically pad-mounted and noted that weight is not a big concern. (PG&E, Pub. Mtg. Tr., No. 34 at p. 74)

For the NOPR engineering analysis, DOE did not restrict its designs based on a limit for size or weight beyond the fixed height measurements it was already considering for the rectangular tank sizes. DOE understands that larger transformers may require additional installation costs such as a new pole change-out or vault expansion. To the extent that it had data on these additional costs, DOE accounted for them in its LCC analysis, as described in section IV.F. However, DOE did not choose to limit its design specifications based on a specific size or weight constraint.

During negotiation meetings, several parties noted that transformers in underground vaults could face staggering cost increases if obligated to comply with unmodified standards. (ABB, Pub. Mtg. Tr., No. 89 at p. 245) The parties proposed to create a separate equipment class for such units and began discussing how such a class might be defined in terms of physical features and such that it would not represent a standards loophole. DOE requests comment on the possibility of establishing a separate equipment class for vault transformers and how such a class could be defined.

Nonetheless, DOE notes that the majority of its designs are within the weight constraints suggested by Power Partners. In design line 2, over 95 percent of DOE's designs are below 650 pounds. In design line 3, over 62 percent of DOE's designs are below 3,600 pounds, and when only the designs with the lowest first cost are considered, nearly 74 percent of the designs are less than 3,600 pounds. The majority of the designs that exceed 3,600 pounds are at the maximum efficiency levels using an amorphous core steel.

During negotiations, Federal Pacific and HVOLT commented that substation-style designs common to the medium-voltage, dry-type market are larger than the designs that DOE had previously modeled and would exhibit bus and lead losses reflecting their longer buses and leads. (HVOLT, Pub. Mtg. Tr., No. 91 at p. 290)

DOE worked with manufacturers to explore the magnitude of the effect of longer buses and leads and found it to be small relative to the gap between efficiency levels. Nonetheless, DOE made small upward adjustments to bus and lead losses of all medium-voltage, dry-type design lines. Details on the specific values of the adjustments made can be found in Chapter 5 of the TSD.

D. Markups Analysis

The markups analysis develops appropriate markups in the distribution chain to convert the estimates of manufacturer selling price derived in the engineering analysis to customer prices. In the preliminary analysis, DOE determined the distribution channels for distribution transformers, their shares of the market, and the markups associated with the main parties in the distribution chain, distributors, contractors and electric utilities.

Several stakeholders commented that DOE's analysis failed to include the distribution channel that delivers liquid-immersed transformers directly from manufacturers to large utilities. (NEEA, No. 11 at p. 2, Joint Comments PG&E and SCE, No. 32 at p. 2, and EMS, Public Meeting Transcript, No. 34 at p. 145) EMS Consulting commented that when large utilities purchase directly from manufacturers, the commission of the manufacturer's representative is included in the price of the transformer and should not be added in separately. (EMS, Public Meeting Transcript, No. 34 at p. 145) PG&E and SCE noted that because utilities often pay much less for transformers purchased in bulk, the selling prices DOE presented in the preliminary analysis are too high. (Joint Comments PG&E and SCE, No. 32 at p. 2) For the NOPR, DOE added a new distribution channel to represent the direct sale of transformers to independently owned utilities, which account for approximately 80 percent of liquid-immersed transformer shipments. This sales channel removes a distributor markup, which had included the commission of the manufacturer's representative in the preliminary analysis. The inclusion of this channel reduces the overall markup for liquid-immersed transformers.

EEI stated that a distribution channel from manufacturers to distributors to multi-site commercial and/or industrial customers (*i.e.,* large purchasers) may represent 10 percent to 25 percent of dry-type transformer sales. (EEI, No. 29 at p. 6) DOE did not find data that would allow it to include the channel mentioned by EEI as a separate distribution channel.

In the preliminary analysis, DOE developed average distributor and contractor markups by examining the installation and contractor cost estimates provided by *RS Means Electrical Cost Data 2011.* DOE developed separate markups for baseline products (baseline markups) and for the incremental cost of more-efficient products (incremental markups). Incremental markups are coefficients that relate the change in the installation cost due to the increase equipment weight of some higher-efficiency models.

FPT agreed with the distributor markups that DOE developed for liquid-immersed transformers. (FPT, No. 27 at p. 17) HPS agreed that a 15-percent markup is appropriate for distributor markup. (HPS, No. 3 at p. 6) ABB and NEMA, on the other hand, recommended that DOE consult with a sample of major distributors to obtain a better understanding of internal markups. (ABB, No. 14 at p. 18; NEMA, No. 13 at p. 8) DOE was not able to conduct a representative survey of transformer distributors within the context of the current rulemaking. Given the supportive comments from FPT and HPS, DOE retained the markup used in the preliminary analysis for the NOPR for liquid-immersed and low-voltage dry-type transformers. However, based on input received from manufacturers during the negotiated rulemaking process, DOE revised the distributor and contractor markups that affect the retail price for medium-voltage dry-type transformers to 1.26 and 1.16, respectively.

HVOLT suggested that DOE's estimated contractor labor and materials markup that affects the installation costs of 1.43 is too high. (HVOLT, Public Meeting Transcript, No. 34 at p. 149) DOE used *RS Means Electrical Cost Data 2010* to estimate a contractor labor and materials markup of 1.43. This markup is justified as it includes: (1) Direct labor required for installation, including unloading, uncrating, hauling within 200 feet of the loading dock, setting in place, connecting to the distribution network, and testing; and (2) equipment rentals necessary for completion of the installation such as a forklift, and/or hoist.

Chapter 6 of the NOPR TSD provides additional detail on the markups analysis.

E. Energy Use Analysis

The energy use and end-use load characterization analysis (chapter 6) produced energy use estimates and end-use load shapes for distribution transformers. The energy use estimates enabled evaluation of energy savings from the operation of distribution transformer equipment at various efficiency levels, while the end-use load characterization allowed evaluation of the impact on monthly and peak demand for electricity from the operation of transformers.

The energy used by distribution transformers is characterized by two types of losses. The first are no-load losses, which are also known as core losses. No-load losses are roughly constant and exist whenever the transformer is energized (*i.e.,* connected to live power lines). The second are load losses, which are also known as resistance or I^2R losses. Load losses vary with the square of the load being served by the transformer.

Because the application of distribution transformers varies significantly by type of transformer (liquid-immersed or dry-type) and ownership (electric utilities own approximately 95 percent of liquid-immersed transformers, commercial/industrial entities use mainly dry-type), DOE performed two separate end-use load analyses to evaluate distribution transformer efficiency. 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. For dry-type transformers, the analysis assumes that these are owned by commercial and industrial customers, so the energy and cost savings estimates are based on monthly building-level demand and energy consumption data and marginal electricity prices. In both cases, the energy and cost savings are estimated for individual transformers and aggregated to the national level using weights derived from either utility or commercial/industrial building data.

For utilities, the cost of serving the next increment of load varies as a function of the current load on the system. To correctly estimate the cost impacts of improved transformer efficiency, it is therefore important to capture the correlation between electric system loads and operating costs and between individual transformer loads and system loads. For this reason, DOE estimated hourly loads on individual liquid-immersed transformers using a statistical model that simulates two relationships: (1) The relationship between system load and system marginal price; and (2) the relationship between the transformer load and system load. Both are estimated at a regional level.

DOE received a number of comments on its preliminary analysis for liquid-immersed transformers.

Regarding the price-load correlation incorporated into the end-use load characterization, EEI suggested that DOE obtain data for 2009/2010 to develop a more complete picture of the savings associated with reducing core and coil losses in liquid-filled transformers. (EEI, No. 29 at p. 6) Because changes to the functional form of the price-load correlation are small compared to the variability in the model, updating the data will not affect the resulting price-load correlation. Thus, DOE continued to use 2008 *Federal Energy Regulatory Commission (FERC) Form714* lambda data and market prices for the NOPR analysis.

EEI also suggested that DOE use tariffs to determine the prices paid for base load electricity generation, because reducing the constant core losses will not save electricity at marginal rates. (EEI, No. 29 at p. 8) NRECA stated that most NRECA members make wholesale purchases at tariff rates that reflect installed, existing resources, with only a small increment based on hourly, market-based purchases. (NRECA, No. 31 and 36 at p. 4) They concluded that DOE's approach overemphasized rates for purchases made on the hourly market.

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. DOE produced a detailed comparison of tariff-based marginal prices and hourly marginal prices for peaking end-uses as part of the Commercial Unitary Air Conditioner & Heat Pump rulemaking.[28] This analysis confirmed that, on an annual average basis, both methods lead to similar cost estimates.

Regarding hourly load data, NEMA recommended that DOE consult with utilities, building owners, and other end-users to obtain any available field data. (NEMA, No. 13 at p. 8) DOE consulted with a variety of industry contacts but was unable to find any source of metered hourly load for transformers. Data submitted by subcommittee member K. Winder of Moon Lake Electric during the negotiations were used to validate the load models for single-phase liquid-immersed transformers. For the final rule, if stakeholders are able to provide, or assist in providing such data, DOE will use it to validate and modify the transformer load models as needed.

Dry-type transformers are primarily installed on buildings and owned by the building owner/operator. Commercial and industrial (C&I) utility customers are typically billed monthly, with the bill based on both electricity consumption and demand. Hence, the value of improved transformer efficiency depends on both the load impacts on the customer's electricity consumption and demand and the customer's marginal prices.

The customer sample of dry-type distribution transformer owners was taken from the EIA Commercial Buildings Energy Consumption Survey (CBECS) databases. Survey data for the years 1992 and 1995 were used, as these are the only years for which monthly customer electricity consumption (kWh) and peak demand (kW) are provided. To account for changes in the distribution of building floor space by building type and size, the weights defined in the 1992 and 1995 building samples were rescaled to reflect the distribution in the most recent 2003 CBECS survey. CBECS covers primarily commercial buildings, but a significant fraction of transformers are shipped to industrial building owners. To account for this in the sample, data from the 2006 Manufacturing Energy Consumption Survey (MECS) were used to estimate the amount of floor space of buildings that might use the type of transformer covered by the rulemaking. The weights assigned to the building sample were rescaled to reflect this additional floor space. Only the weights of large buildings were rescaled.

Regarding DOE's energy use characterization, EEI stated that DOE should use EIA's 2006 MECS to develop baseline electricity consumption and demand for industrial facilities. (EEI, No. 29 at p. 8) Using CBECS data as a proxy, they said, may lead to incorrect analysis on transformers for the industrial facilities being modeled. (EEI, No. 29 at p. 8) The MECS survey data does not contain any building-level information on energy consumption, and contains no information whatsoever on electricity demand. Thus, DOE retained use of CBECS data for the NOPR analysis.

Transformer loading is an important factor in determining which types of transformer designs will deliver a specified efficiency, and for calculating transformer losses. In the preliminary

[28] See *http://www1.eere.energy.gov/buildings/appliance_standards/commercial/ac_hp.html.*

analysis, DOE assumed non-residential load factors of 35 percent, 40 percent, and 25 percent for medium-voltage single-phase, medium-voltage three-phase, and low-voltage transformers respectively. Several stakeholders commented on the load factors DOE used to characterize commercial and industrial loads. EEI suggested that DOE use Electric Power Research Institute (EPRI) and/or utility load factor studies to develop separate commercial and industrial load factors to use in its analysis. (EEI, No. 29 at p. 7) suggested that load factors for large commercial buildings have been trending upward because of the increased numbers of data centers. (HEX, Public Meeting Transcript, No. 34 at p. 192) EEI suggested that, based on EPRI data, DOE use higher load factors (50–55 percent for commercial buildings and 70–80 percent for industrial buildings). (EEI, Public Meeting Transcript, No. 34 at p. 168) ABB stated that DOE's current assumptions about average load factors are sufficiently accurate. (ABB, No. 14 at p. 18) FPT stated commercial and industrial users tend to load their transformers to a lower percent of nameplate than utilities would load residential liquid-filled transformers because of the greater risk and impact of an outage of a transformer in a commercial or industrial installation. (FTP, No. 27 at p. 19)

Several subcommittee members commented that in rural areas the number of customers per transformer is likely to be significantly lower than in urban or suburban areas, which in turn results in lower RMS loads. (APPA and NRECA, Public Meeting Transcript, No. 91 at p. 201) To account for this effect, DOE performed an analysis to determine an average population density in the territory served by each of the utilities represented in the LCC simulation. For each utility, EIA Form 861 data were used to generate a list of counties served by the utility. Census data were used to determine the average housing unit density in each county. An average over counties was then used to assign the utility to a low density, average density or high density category, with the cutoff for low density set at 32 households per square mile. For those utilities serving primarily low density areas the median of the RMS load distribution is reduced from 35 percent to 25 percent.

For the NOPR, DOE modified its analysis of dry-type transformer loading to: (1) model commercial and industrial building installations separately; and (2) reflect how transformers are used in the field. Higher-capacity medium-voltage transformers are loaded at 40 percent and smaller capacity transformers medium-voltage are loaded at 35 percent. Low-voltage transformers are loaded at 25 percent.

DOE received a number of comments that apply to both the hourly and monthly load models.

Regarding load (coil) losses, EEI suggested that DOE use diversity factors to account for the fact that significantly less than 100 percent of load losses are correlated with peak demands for a building or distribution system. Using this method, they said, would prevent overestimating cost savings. (EEI, No. 29 at p. 8) DOE already employs diversity factors to account for the fact that load (coil) losses often do not correlate with system or building peak loads.

Several stakeholders questioned whether DOE's analysis of responsibility factor accounts for the diversity of loads that transformers serve. NRECA, for instance, commented that diversity among a transformer's loads must be considered to set the responsibility factor for an individual transformer, if multiple customers are served through a transformer. (NRECA, No. 31 and 36 at p. 4) EEI also expressed concern that DOE's analysis of responsibility factor excluded diversity of loads. (EEI, No. 29 at p. 7) CDA recommended that DOE's analysis of responsibility factor consider the effect of load (winding) losses that likely occur simultaneously with system peaks. (CDA, No. 17 at p. 3)

The statistical model that DOE uses to estimate the responsibility factor for each individual transformer accounts for the diversity of loads. The responsibility factor model is applied to the load (winding) losses. The model accounts for the effect of diversity of individual transformer loads with respect to the peak of the aggregate load of the system that contains the transformer. Winding losses are included in the analysis.

Several stakeholders commented on DOE's use of a power factor of 1 in its end-use load characterization. PG&E and SCE stated that DOE should consider a power factor less than unity. (Joint Comments PG&E and SCE, No. 32 at p. 1) EEI suggested that DOE use a power factor other than 1 to account for decreased transformer efficiency from increased harmonic parasitic loads. (EEI, Public Meeting Transcript, No. 34 at p. 156)

In DOE's analysis, transformer loss estimates are calculated relative to the peak load on the transformer. The ratio of the peak load on a transformer to the transformer capacity is modeled by a distribution. There are two additional parameters that can affect the overall scale of transformer loading relative to its rated capacity. One is the power factor, and the other is a modeling parameter that adjusts the ratio of the RMS load relative to the square of the transformer peak load. Neither of these factors is known with great accuracy. The LCC spreadsheet allows the user to adjust the power factor. Adjusting the power factor from one to 0.95 may scale the energy losses up slightly, but as all transformer designs are affected equally, there should be no significant impact on the selection of designs that meet the candidate standard level. In the absence of additional field data on both RMS loads and power factors in different transformer installations, DOE does not believe that these small adjustments can significantly improve the accuracy of the LCC calculations.

NEEA commented on the calculation of load losses, recommending that DOE use hourly marginal line losses rather than annual average line losses to adjust distribution transformer loads to system generation loads. It stated that using hourly marginal line losses would more accurately reflect the value of load losses. (NEEA, No. 11 at p. 10) DOE found no data supporting the use of hourly marginal line losses rather than average annual line losses in calculating load losses. Thus, it continued to use average annual line losses for the NOPR analysis.

F. Life-Cycle Cost and Payback Period Analysis

DOE conducts LCC and PBP analyses to evaluate the economic impacts on individual customers of potential energy conservation standards for distribution transformers. The LCC is the total customer expense over the life of a product, consisting of purchase and installation costs plus operating costs (expenses for energy use, maintenance and repair). To compute the operating costs, DOE discounts future operating costs to the time of purchase and sums them over the lifetime of the product. The PBP is the estimated amount of time (in years) it takes customers to recover the increased purchase cost (including installation) of a more efficient product through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost (normally higher) due to a more stringent standard by the change in average annual operating cost (normally lower) that results from the standard.

For any given efficiency level, DOE measures the PBP and the change in LCC relative to an estimate of the base-case efficiency levels. The base-case estimate reflects the market in the absence of amended energy conservation standards, including the market for products that exceed the current energy conservation standards.

Equipment price, installation cost, and baseline and standard affect the installed cost of the equipment. Transformer loading, load growth, power factor, annual energy use and demand, electricity costs, electricity price trends, and maintenance costs affect the operating cost. The compliance date of the standard, the discount rate, and the lifetime of equipment affect the calculation of the present value of annual operating cost savings from a proposed standard. Table IV.1 summarizes all the major inputs to the LCC and PBP analysis, and whether those inputs were revised for the proposed rule.

Commenting on the preliminary analysis, SC stated that because the assumptions DOE uses in its LCC and PBP analyses are not always correct and not specific to an individual utility or user, the conclusions are most likely inaccurate for some utilities. (SC, No. 22 at p. 4) DOE calculated the LCC and PBP for a representative sample (a distribution) of individual transformers. In this manner, DOE's analysis explicitly recognized that there is both variability and uncertainty in its inputs. DOE used Monte Carlo simulations to model the distributions of inputs. The Monte Carlo process statistically captures input variability and distribution without testing all possible input combinations. Some atypical situations may not be captured in the analysis, but DOE believes the analysis captures an adequate range of situations in which transformers operate.

TABLE IV.1—KEY INPUTS FOR THE LCC AND PBP ANALYSES

Inputs	Preliminary analysis description	Changes for proposed rule
Affecting Installed Costs:		
Equipment price	Derived by multiplying manufacturer selling price (from the engineering analysis) by distributor markup and contractor markup plus sales tax for dry-type transformers. For liquid-immersed transformers, DOE used manufacturer selling price plus small distributor markup plus sales tax. Shipping costs were included for both types of transformers.	Added a case for liquid-immersed transformers that are sold directly to utilities.
Installation cost	Includes a weight-specific component, derived from *RS Means Electrical Cost Data 2010* and a markup to cover installation labor, pole replacement costs for design line 2 and equipment wear and tear.	Updated the installation factors to use *RS Means Electrical Cost Data 2011.* Improved the modeling of pole replacements for design line 2.
Baseline and standard design selection	The selection of baseline and standard-compliant transformers depended on customer behavior. For liquid-immersed transformers, the fraction of purchases evaluated was 75%, while for dry-type transformers, the fraction of evaluated purchases was 50% for small capacity medium-voltage and 80% for large-capacity medium-voltage.	Adjusted the percent of evaluators to: 10% for liquid-immersed transformers, and 2% for low-voltage dry-type and 2% for medium-voltage dry-type transformers.
Affecting Operating Costs:		
Transformer loading	Loading depended on customer and transformer characteristics.	Adjusted loading as a function of transformer capacity and utility customer density.
Load growth	0.5% per year for liquid-immersed and 0% per year for dry-type transformers.	No change.
Power factor	Assumed to be unity	No change.
Annual energy use and demand	Derived from a statistical hourly load simulation for liquid-immersed transformers, and estimated from the 1992 and 1995 *Commercial Building Energy Consumption Survey* data for dry-type transformers using factors derived from hourly load data. Load losses varied as the square of the load and were equal to rated load losses at 100% loading.	No change.
Electricity costs	Derived from tariff-based and hourly based electricity prices. Capacity costs provided extra value for reducing losses at peak.	No change.
Electricity price trend	Obtained from *Annual Energy Outlook 2010* (*AEO2010*).	Updated to *Annual Energy Outlook 2011 (AEO 2011).*
Maintenance cost	Annual maintenance cost did not vary as a function of efficiency.	No change.
Compliance date	Assumed to be 2016	No change.
Discount rates	Mean real discount rates ranged from 4.0% for owners of pole-mounted, liquid-immersed transformers to 5.1% for dry-type transformer owners.	The mean real discount rates were adjusted to 3.7% for owners of liquid-immersed transformers and 4.6% for dry-type transformers.
Lifetime	Distribution of lifetimes, with mean lifetime for both liquid and dry-type transformers assumed to be 32 years.	No change.

The following sections contain brief discussions of comments on the inputs and key assumptions of DOE's LCC analysis and explain how DOE took these comments into consideration.

1. Modeling Transformer Purchase Decision

The LCC spreadsheet uses a purchase-decision model that specifies which of the hundreds of designs in the engineering database are likely to be selected by transformer purchasers to meet a given efficiency level. The engineering analysis yielded a cost-efficiency relationship in the form of manufacturer selling prices, no-load losses, and load losses for a wide range of realistic transformer designs. This set of data provides the LCC model with a distribution of transformer design choices.

DOE used an approach that focuses on the selection criteria customers are known to use when purchasing transformers. Those criteria include first costs, as well as what is known in the transformer industry as total owning cost (TOC). The TOC method combines first costs with the cost of losses. Purchasers of distribution transformers, especially in the utility sector, have long used the TOC method to determine which transformers to purchase. DOE refers to purchasers who use the TOC method as evaluators.

The utility industry developed TOC evaluation as an easy-to-use tool to reflect the unique financial environment faced by each transformer purchaser. To express variation in such factors as the cost of electric energy, and capacity and financing costs, the utility industry developed a range of evaluation factors, called A and B values, to use in their calculations. A and B are the equivalent first costs of the no-load and load losses (in $/watt), respectively.

In the preliminary analysis, DOE assumed that 75 percent of liquid-immersed transformers are purchased using TOC evaluation. DOE assumed that 25 percent of low-voltage dry-type transformers are purchased using TOC evaluation. For medium-voltage dry-type transformers, DOE assumed that 50 percent of smaller capacity units are purchased with TOC evaluation and that 85 percent of larger capacity units are purchased using TOC evaluation.

Several stakeholders commented on DOE's estimate of the share of purchasers who make purchase decisions based on TOC. FPT said that DOE significantly overstated the percentage of evaluators for dry-type distribution transformers. They estimated there are 0 percent to 1 percent evaluators for low-voltage dry-type, about 10 percent for medium-voltage dry-type, and about 20 percent for high-capacity dry-type distribution transformers. (FPT, No. 27 at p. 4) ABB agreed that DOE overestimated the number of evaluators. They estimated that evaluators represent less than 1 percent for low-voltage dry-type and small medium-voltage dry-type, and less than 5 percent for large medium-voltage dry-type. (ABB, No. 14 at p. 19) Other stakeholders agreed that DOE's estimates of evaluators are too high. (EEI, No. 29 at p. 8; ASAP, Public Meeting Transcript, No. 34 at p. 197) NEMA commented that the percent of evaluators seems high for some product lines, and recommended that DOE obtain information from individual manufacturers and end-users, or examine shipments data to determine evaluators. (NEMA, No. 13 at p. 8) ASAP *et al.* recommended that the DOE survey enough users and suppliers to develop a better estimate of the percentage of units purchased in 2010 that had significantly higher efficiency than the minimum standard. (Joint Comments ASAP, ACEEE and NRDC, No. 28 at p. 4)

Conducting a representative survey of users or manufacturers is not possible within the scope of the present rulemaking. For the NOPR analysis, DOE revised the evaluation rates, based on the available data and stakeholder comments. DOE revised its evaluation rates as follows: 10 percent for liquid-immersed, 2 percent for low-voltage, and 2 percent for medium-voltage dry-type transformers. The transformer selection approach is discussed in detail in chapter 8 of the NOPR TSD.

FPT stated that only utilities really evaluate based on A and B factors, so another method needs to be used to analyze other types of customers. FPT recommended that DOE base its analysis of industrial and commercial customers on PBP criteria. (FPT, No. 27 at p. 5) DOE effectively bases its analysis on PBP; the results are converted to equivalent A and B factors so that the same model structure can be used in all the spreadsheets.

HI stated that fewer customers will evaluate their purchases when DOE mandates higher efficiency levels, which would result in purchase of transformers with less than optimum efficiency for their application. (HI, No. 23 at p. 9) DOE acknowledges that evaluation rates may vary depending on the standard for a given design line. Because DOE has no basis for estimating this phenomenon, however, it used the same evaluation rates for each of the considered CSLs.

2. Inputs Affecting Installed Cost

a. Equipment Costs

In the LCC and PBP analysis, the equipment costs faced by distribution transformer purchasers are derived from the MSPs estimated in the engineering analysis and the overall markups estimated in the markups analysis.

Several stakeholders recommended that DOE lower its estimate of transformer selling prices. Based on its Internet review of selling prices, Metglas said the prices DOE generated are too high. (MET, Public Meeting Transcript, No. 34 at p. 97) PG&E and SCE suggested that DOE calibrate its prices against market data and exclude the cost of any additional features from the price estimates. (Joint Comments PG&E and SCE, No. 32 at p. 2) ASAP, ACEEE and NRDC agreed that DOE's estimated selling prices are too high, and recommended that DOE adjust its estimates based on market research, and then apply an adjustment factor to bring final transformer selling prices in line with observed prices. (Joint Comments ASAP, ACEEE and NRDC, No. 28 at pp. 1–2)

For the NOPR analysis, DOE reviewed bid documents on the Internet after the current standards took effect in 2010 and found a wide range of prices. DOE also received confidential data from NEEA on utility transformer purchases that showed a wide range of prices. The data did not clearly indicate that DOE's estimated customer prices are too high. DOE notes that the inclusion of a new distribution channel for liquid results in a lower average markup and thus lower average customer price for these products.

EEI stated that DOE should consider transformer pricing data from 2006 onward, because that period reflects the increasing global demand for distribution transformers as well as the increase in commodity costs for key transformer components. EEI asserted that transformer prices have not declined, but rather increased, compared to the rate of inflation. (EEI, No. 29 at pp. 2–4)

To forecast a price trend for the NOPR, DOE derived an inflation-adjusted index of the PPI for electric power and specialty transformer manufacturing over 1967–2010. These data show a long-term decline from 1975 to 2003, and then a steep increase since then. DOE believes that there is considerable uncertainty as to whether the recent trend has peaked, and would be followed by a return to the previous long-term declining trend, or whether the recent trend represents the beginning of a long-term rising trend due to global demand for distribution transformers and rising commodity costs for key transformer components. Given the uncertainty, DOE has chosen to use constant prices (2010 levels) for both its LCC and PBP analysis and the NIA. For the NIA, DOE also analyzed the sensitivity of results to alternative transformer price forecasts. DOE developed one forecast in which prices decline after 2010, and one in which prices rise. Appendix 10–C of the NOPR TSD describes the historic data and the derivation of the default and alternative price forecasts.

DOE requests comments on the most appropriate trend to use for real transformer prices, both in the short run (to 2016) and the long run (2016–2045).

b. Installation Costs

Higher efficiency distribution transformers tend to be larger and heavier than less efficient designs. In the preliminary analysis, DOE included the increased cost of installing larger, heavier transformers as a component of the first cost of more efficient transformers. DOE presented the installation cost model and solicited comment from stakeholders.

Commenting on the preliminary analysis, several stakeholders stated that DOE should revise its assumption that 25 percent of pole-mounted liquid-immersed transformers greater than 1,000 pounds will require an additional $2,000 cost for pole change-out. (Joint Comments PG&E and SCE, No. 32 at p. 2; Joint Comments ASAP, ACEEE and NRDC, No. 28 at p. 2–3; NEEA, No. 11 at p. 8) The above comments reflect a misunderstanding of DOE's preliminary analysis. The 25 percent referred to in the comments was the maximum pole change-out fraction in the algorithm DOE used to estimate when change-outs would be required when the weight of the transformer exceeds 1,000 pounds.

EEI noted that several of its members expressed concern that more efficient liquid-immersed transformers would have much higher weights, which would increase costs in terms of installation and pole structural integrity for retrofits of existing pole-mounted transformers. (EEI, No. 29 at p. 2) APPA commented that DOE must adequately account for the costs of pole replacements due to larger transformers. (APPA, No. 21 at p. 2) SC stated that pole change-outs may be necessary when transformers are replaced because larger diameter poles will be needed to support transformer weight increases, and that larger diameter poles may be required with new transformer installations. (SC, No. 22 at p. 3) ComEd commented that for pole-mounted transformers, an increase in transformer weight may generate an increase in the required pole class to sustain the load. (ComEd, No. 24 at p. 1) PP agreed that additional transformer weight could make pole-mounting difficult. (PP, No. 19 at p. 1) NRECA and T&DEC stated that the added cost of replacing utility poles is especially burdensome for rural electric cooperatives. (Joint Comments NRECA and T&DEC, No. 31 and 36 at pp. 1–2)

Other stakeholders stated that standards that result in heavier transformers would not necessarily require pole change-outs. ASAP *et al.* stated that increased weight due to higher efficiency will not require pole change-outs. They noted that the primary determining factor in selecting pole size is the horizontal load, not the vertical load, which is affected by the transformer weight. (Joint Comments ASAP, ACEEE and NRDC, No. 28 at p. 2–3) PG&E and SCE stated that replacement of the pole (or pad) is more a function of transformer upsizing than of increased size due to efficiency improvement, adding that when replacing in-kind utility transformers, the rate of pole change-out due to increased size and weight of higher-efficiency improvements is very low. They also noted that for new construction, pole change-out is unnecessary because there is no existing pole to change out. (Joint Comments PG&E and SCE, No. 32 at p. 2)

In general, as transformers are redesigned to reach higher efficiency, the weight and size also increase. The degree of weight increase depends on how the design is modified to improve efficiency. For pole-mounted transformers, represented by design line (DL) 2, the increased weight may lead to situations where the pole needs to be replaced to support the additional weight of the transformer. This in turn leads to an increase in the installation cost. To account for this effect in the analysis, three steps are needed:

The first step is to determine whether the pole needs to be changed. This depends on the weight of the transformer in the base case compared to the weight of the transformer under a proposed efficiency level, and on assumptions about the load-bearing capacity of the pole. In the LCC calculation, it is assumed that a pole change-out will only be necessary if the weight increase is larger than 15 percent and greater than 150 lbs of the weight of the baseline unit. Utility poles are primarily made of wood. Both ANSI and NESC provide guidelines on how to estimate the strength of a pole based on the tree species, pole circumference and other factors. Natural variability in wood growth leads to a high degree of variability in strength values across a given pole class. Thus, NESC also provides guidelines on reliability, which result in an acceptable probability that a given pole will exceed the minimal required design strength. Because poles are sized to cope with large wind stresses and potential accumulation of snow and ice, this results in ''over-sizing'' of the pole relative to the load by a factor of two to four. Because of this ''over-sizing'' DOE limited the total fraction of pole replacements to 25 percent of the total population.

The second step is to determine the cost of a pole change-out. Specific examples of pole change-out costs were submitted by the sub-committee. These examples were consistent with data taken from the RSMeans Building Construction Cost database. Based on this information, a triangular distribution was used to estimate pole change-out costs, with a lower limit at $2,025 and an upper limit at $5,999. Utility poles have a finite life-time, so that pole change-out due to increased transformer weight should be counted as an early replacement of the pole; *i.e.* it is not correct to attribute the full cost of pole replacement to the transformer purchase. Equivalently, if a pole is changed out when a transformer is replaced, it will have a longer lifetime relative to the pole it replaces, which offsets some of the cost of the pole installation. To account for this affect, pole installation costs are multiplied by a factor *n/pole-lifetime,* which approximately represents the value of the additional years of life. The parameter *n* is chosen from a flat distribution between 1 and the pole lifetime, which is assumed to be 30 years.[29]

PHI noted that if a pole-mount transformer exceeds 900 pounds, they are required to have two crews for the replacement, a heavy-duty rigger and traffic control crew, adding to the expense of the installation. (PHI, No. 26 at p. 1) DOE's analysis accounts for increase in installation labor costs as transformer weight increases and is described in detail in chapter 6 of the NOPR TSD.

Regarding pad-mounted transformers, ComEd commented that new standards

[29] As the LCC represents the costs associated with purchase of a single transformer, to account for multiple transformers mounted on a single pole, the pole cost should also be divided by a factor representing the average number of transformers per pole. No data is currently available on the fraction of poles that have more than one transformer, so this factor is not included.

could require that the pads for some pad-mounted transformers receive foundation upgrades to accommodate the increased size and weight, which might require that generators be deployed to maintain customer services during the upgrade. (ComEd, No. 24 at p. 3) APPA also stated that DOE must adequately account for the costs of pad mount replacements due to larger transformers. (APPA, No. 21 at p. 2) HI noted that symmetric core technology could affect installation practices because the core design has a triangular footprint that requires a much deeper pad to accommodate the deeper tanks. (HI, No. 23 at p. 3) At present, DOE's model does not include any additional costs that may be required for pad-mounted transformers at higher efficiency levels. DOE requests data on the weight and size thresholds that might be expected to trigger pad mount upgrades and on approximate costs of a typical upgrade.

DOE received comments on the affect that that symmetric core technology would have on installation costs. NRECA described theoretical evaluation that indicates weight and labor costs would increase for symmetric core technology. (NRECA, No. 31 and 36 at p. 3) The engineering analysis estimated the weight of transformers that utilize symmetric core technology. As mentioned above, the LCC and PBP analysis accounts for increase in installation labor costs as transformer weight increases.

EEI noted that several of its members expressed concern that more efficient transformers will be larger in size (height, width, and depth), which will have an impact for all retrofit situations, especially in underground vaults, which in many urban areas cannot be physically expanded, or can only be expanded at a great cost in terms of materials, labor, and street closures. (EEI, No. 29 at p. 2) Because vault-installed transformers account for a small fraction of transformer installations, and mainly affect urban utilities that have underground distribution systems, DOE chose to analyze these transformers as part of the customer subgroup analysis. This analysis, and the approach DOE used to account for installing larger-volume transformers, is described in section IV.H.

3. Inputs Affecting Operating Costs

a. Transformer Loading

DOE's assumptions about loading of different types of transformers are described in section IV.E. DOE generally estimated the loading on larger transformers is greater than the loading on smaller transformers.

b. Load Growth Trends

The LCC takes into account the projected operating costs for distribution transformers many years into the future. This projection requires an estimate of how the electrical load on transformers will change over time. In the preliminary analysis, for dry-type transformers, DOE assumed no load growth, while for liquid-immersed transformers DOE used as the default scenario a one-percent-per-year load growth. It applied the load growth factor to each transformer beginning in 2016. To explore the LCC sensitivity to variations in load growth, DOE included in the model the ability to examine scenarios with zero percent, one percent, and two percent load growth.

DOE did not receive comments regarding its load growth assumptions, and it retained the assumptions described above for the NOPR analysis.

c. Electricity Costs

DOE needed estimates of electricity prices and costs to place a value on transformer losses for the LCC calculation. As discussed in section IV.E, DOE created two sets of electricity prices to estimate annual energy expenses for its analysis: an hourly-based estimate of wholesale electricity costs for the liquid-immersed transformer market, and a tariff-based estimate for the dry-type transformer market. IV.E also presents the comments received on this topic and DOE's response.

DOE received a few comments regarding electricity cost estimation. Electricity cost estimates are discussed in detail in chapter 7 of the NOPR TSD.

d. Electricity Price Trends

For the relative change in electricity prices in future years, DOE relied on price forecasts from the Energy Information Administration (EIA) *Annual Energy Outlook* (*AEO*). For the preliminary analysis, DOE used price forecasts from *AEO 2011*.

PG&E and SCE considered DOE's forecasted electricity prices in the preliminary analysis to be low. They recommended that DOE revisit their electric price forecast to ensure it accurately reflects historical trends and potential future global scenarios that may drive electricity prices higher than otherwise anticipated. (Joint Comments PG&E and SCE, No. 32 at p. 2) For the proposed rule, DOE updated the price forecast to *AEO 2011* and examined the sensitivity of analysis results to changes in electricity price trends. Appendix 8–D of the NOPR TSD provides a sensitivity analysis for equipment of each product group with the largest market shares, for liquid-immersed transformers design lines 1 and 5 are examined, for low-voltage dry-type transformers design line 7 is examined, and for medium-voltage dry-type transformers design line 12. These analysis shows that the effect of changes in electricity price trends, compared to changes in other analysis inputs, is relatively small. DOE evaluated a variety of potential sensitivities, and the robustness of analysis results with respect to the full range of sensitivities, in weighing the potential benefits and burdens of the proposed rule.

e. Standards Compliance Date

DOE calculated customer impacts as if each new distribution transformer purchase occurs in the year manufacturers must comply with the standard. For the preliminary analysis, this was assumed to be January 1, 2016.

Several stakeholders commented on the compliance date for new efficiency standards for distribution transformers. Howard Industries stated that the feasibility of the proposed date depends on the magnitude of changes in the new rulemaking and the supply chain limitations that will occur once the economy recovers. They estimated that they will need until the January 1, 2016, date to comply with new efficiency levels for liquid-immersed distribution transformers. (HI, No. 23 at p. 1) EEI agreed that the compliance date for any new standards should be no sooner than January 1, 2016. (EEI, No. 29 at p. 4) Schneider Electric commented that the previous standard for low-voltage dry-type transformers was implemented within 16 months because many manufacturers already were producing enough compliant transformers that it was a stock product. It noted that circumstances are not the same for the new standard levels, and a longer period should be allowed for compliance. (SE., No. 18 at p. 5) (NEEA agreed with the current compliance date, but said that if the final rule is not stringent, DOE should consider an earlier date and/or should examine the interaction between stringency of standards with the number of models already in production. (NEEA, No. 11 at p. 10)

As discussed in section II.A, if DOE finds that amended standards for distribution transformers are warranted, DOE must publish a final rule containing such amended standards by October 1, 2012. The statutorily-required compliance date of January 1, 2016, provides manufacturers with over three years to prepare for manufacturing distribution transformers to the new standards.

f. Discount Rates

The discount rate is the rate at which future expenditures are discounted to estimate their present value. DOE employs a two-step approach in calculating discount rates for analyzing customer economic impacts. The first step is to assume that the actual customer cost of capital approximates the appropriate customer discount rate. The second step is to use the use the capital asset pricing model (CAPM) to calculate the equity capital component of the customer discount rate. For the preliminary analysis, DOE estimated a statistical distribution of commercial customer discount rates that varied by transformer type by calculating the cost of capital for the different types of transformer owners.

Commenting on the preliminary analysis, EEI stated that small businesses and entities under financial duress likely would face significantly higher effective discount rates. (EEI, No. 29 at p. 8) The intent of the LCC analysis is to estimate the economic impacts of higher-efficiency transformers over a representative range of customer situations. While the discount rates used may not be applicable for all customers, DOE believes that they reflect the financial situation of the majority of transformer customers.

More detail regarding DOE's estimates of commercial customer discount rates is provided in chapter 8 of the NOPR TSD.

g. Lifetime

DOE defined distribution transformer life as the age at which the transformer retires from service. For the preliminary analysis, DOE assumed, based on a report by Oak Ridge National Laboratory,[30] that the average life of distribution transformers is 32 years. This lifetime assumption includes a constant failure rate of 0.5 percent/year due to lightning and other random failures unrelated to transformer age and an additional corrosive failure rate of 0.5 percent/year starting at year 15.

Commenting on this assumption, HVOLT and PHI suggested that DOE use a lifetime of 30 years. (HVOLT, Public Meeting Transcript, No. 34 at p. 126; PHI, Public Meeting Transcript, No. 34 at p. 210) DOE did not receive any additional data that provide a basis for changing its 32-year assumption on distributor lifetime, so it retained the approach used in the preliminary analysis for the NOPR analysis.

h. Base Case Efficiency

To determine an appropriate base case against which to compare various candidate standard levels, DOE used the purchase-decision model described in section IV.F.1. For the base case, initially transformer purchasers are allowed to choose among the entire range of transformers at each design line.

During the negotiation process, ERAC subcommittee members noted that currently there are no transformers using ZDMH as a core material sold in the U.S. market. (ABB, Public Meeting Transcript, No. 91 at p. 276) Therefore, DOE screened out designs using this material in the base case selection. For higher efficiency levels, the LCC analysis samples from all design options identified in the engineering analysis.

Subcommittee members provided data on market share as a function of efficiency. For some design lines, the lower boundary of the price-efficiency curve produced in the engineering analysis is quite flat, so that the choice algorithm in the LCC analysis showed units being selected in the base case with efficiencies substantially higher than the current DOE minimum standard. DOE modified its approach so that the fraction of units selected in the base case at different efficiency levels is consistent with the provided market share data.

G. National Impact Analysis—National Energy Savings and Net Present Value Analysis

DOE's NIA assessed the national energy savings (NES) and the national NPV of total customer costs and savings that would be expected to result from amended standards at specific efficiency levels. (''Customer'' refers to purchasers of the product being regulated.)

To make the analysis more accessible and transparent to all interested parties, DOE used an MS Excel spreadsheet model to calculate the energy savings and the national customer costs and savings from each TSL. DOE understands that MS Excel is the most widely used spreadsheet calculation tool in the United States and there is general familiarity with its basic features. Thus, DOE's use of MS Excel as the basis for the spreadsheet models provides interested parties with access to the models within a familiar context. In addition, the TSD and other documentation that DOE provides during the rulemaking help explain the models and how to use them, and interested parties can review DOE's analyses by changing various input quantities within the spreadsheet.

DOE used the NIA spreadsheet to calculate the NES and NPV, based on the annual energy consumption and total installed cost data from the energy use characterization and the LCC analysis. DOE forecasted the energy savings, energy cost savings, product costs, and NPV of customer benefits for each product class for products sold from 2016 through 2045. The forecasts provided annual and cumulative values for all four output parameters. In addition, DOE analyzed scenarios that used inputs from the *AEO 2011* Low Economic Growth and High Economic Growth cases. These cases have higher and lower energy price trends compared to the Reference case. NIA results based on these cases are presented in appendix 10–B of the NOPR TSD.

DOE evaluated the impacts of amended standards for distribution transformers by comparing base-case projections with standards-case projections. The base-case projections characterize energy use and customer costs for each product class in the absence of amended energy conservation standards. DOE compared these projections with projections characterizing the market for each product class if DOE were to adopt amended standards at specific energy efficiency levels (*i.e.*, the standards cases) for that class.

The tables below summarize all the major NOPR inputs to the shipments analysis and the NIA, and whether those inputs were revised for the proposed rule.

TABLE IV.2—INPUTS FOR THE SHIPMENTS ANALYSIS

Input	Preliminary analysis description	Changes for proposed rule
Shipments data	Third-party expert (HVOLT) for 2009	No change.

[30] Barnes. Determination Analysis of Energy Conservation Standards for Distribution Transformers. ORNL–6847. 1996.

TABLE IV.2—INPUTS FOR THE SHIPMENTS ANALYSIS—Continued

Input	Preliminary analysis description	Changes for proposed rule
Shipments forecast	2016–2045: Based on *AEO 2010*	Updated to AEO 2011.
Dry-type/liquid-immersed market shares	Based on EIA's electricity sales data and *AEO2010*.	Updated to AEO 2011.
Regular replacement market	Based on a survival function constructed from a Weibull distribution function normalized to produce a 32-year mean lifetime. Source: ORNL 6804/R1, *The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance,* page D–1.	No change.
Elasticities, liquid-immersed	For liquid-immersed transformers: • Low: 0.00 • Medium: −0.04 • High: −0.20	No change.
Elasticities, dry-type	For dry-type transformers: • Low: 0.00 • Medium: −0.02 • High: −0.20	No change.

TABLE IV.3—INPUTS FOR THE NATIONAL IMPACT ANALYSIS

Input	Preliminary analysis description	Changes for proposed rule
Shipments	Annual shipments from shipments model	No change.
Compliance date of standard	January 1, 2016	No change.
Base case efficiencies	Constant efficiency through 2044. Equal to weighted-average efficiency in 2016.	No change.
Standards case efficiencies	Constant efficiency at the specified standard level from 2016 to 2044.	No change.
Annual energy consumption per unit	Average rated transformer losses are obtained from the LCC analysis, and are then scaled for different size categories, weighted by size market share, and adjusted for transformer loading (also obtained from the LCC analysis).	No change.
Total installed cost per unit	Weighted-average values as a function of efficiency level (from LCC analysis).	No change.
Electricity expense per unit	Energy and capacity savings for the two types of transformer losses are each multiplied by the corresponding average marginal costs for capacity and energy, respectively, for the two types of losses (marginal costs are from the LCC analysis).	No change.
Escalation of electricity prices	*AEO 2010* forecasts (to 2035) and extrapolation for 2044 and beyond.	Updated the escalation of electricity prices forecast using AEO 2011.
Electricity site-to-source conversion	A time series conversion factor; includes electric generation, transmission, and distribution losses. Conversion varies yearly and is generated by DOE/EIA's National Energy Modeling System (NEMS) program.	Updated conversion factors from NEMS.
Discount rates	3% and 7% real	No change.
Present year	Equipment and operating costs are discounted to the year of equipment price data, 2010.	No change.

1. Shipments

DOE constructed a simplified forecast of transformer shipments for the base case by assuming that long-term growth in transformer shipments will be driven by long-term growth in electricity consumption. The detailed dynamics of transformer shipments is highly complex. This complexity can be seen in the fluctuations in the total quantity of transformers manufactured as expressed by the U.S. Department of Commerce, Bureau of Economic Analysis (BEA), transformer quantity index. DOE examined the possibility of modeling the fluctuations in transformers shipped using a bottom-up model where the shipments are triggered by retirements and new capacity additions, but found that there were not sufficient data to calibrate model parameters within an acceptable margin of error. Hence, DOE developed the transformer shipments forecast assuming that annual transformer shipments growth is equal to forecasted growth in electricity consumption as given by the *AEO 2011* forecast up to the year 2035. For the years from 2036 to 2045, DOE extrapolated the *AEO 2011* forecast with the growth rate of electricity consumption from 2025 to 2035. The model starts with an estimate of the overall growth in transformer capacity and then estimates shipments for particular design lines and transformer sizes using estimates of the recent market shares for different design and size categories. Chapter 9 provides a detailed description of how DOE conducted its shipments forecasts.

EEI suggested that the shipment projections are overly optimistic and should be closer to a flat line of growth. (EEI, No. 29 at p. 9) The historical shipments data based on the BEA's quantity index data for power and distribution transformers show a relatively flat trend between the late 1970s and 2007. The data show a sharp increase in 2008, a higher-than-average level in 2009, and a steep plunge in 2010. This recent trend apparently reflects purchasers stocking up on transformers in advance of the standards that took effect in 2010. Given this unusual market situation, DOE believes that holding future shipments at the 2010 level would be unrealistic. For the NOPR, DOE's base case forecast shows shipments gradually returning to the level of 2008 by the end of the forecast period.

Commenting on the preliminary analysis, NEMA noted that in some markets, liquid-immersed and medium-voltage dry-type transformers compete against one another, and for some applications, liquid-immersed units have additional costs for liquid containment or fire protection. NEMA encouraged DOE to consider whether higher prices for liquid-immersed units due to standards might cause users to shift to dry-type transformers. (NEMA, No. 13 at p. 7) ABB said that they have not observed a shift in market share between equipment classes as a result of current regulations, but they asked that any new regulation be analyzed as to its potential impact in shifting demand between equipment classes. (ABB, No. 14 at p. 19)

In principle, the appropriate way to address the probability that a customer switches to a different product class in response to an increase in the price of a specific product is to estimate the cross-price elasticity of demand between competing classes. To estimate this elasticity, DOE would need historical data on the shipments and price of the liquid-immersed and medium-voltage dry-type transformers. The shipments data at that level of disaggregation is available only for two years (2001 and 2009), which is not sufficient to support the estimation of cross-price elasticity of liquid-immersed distribution transformers. Thus, for the NOPR DOE did not estimate potential switching from liquid-immersed to dry-type transformers. DOE requests data that would allow it to estimate such switching for the final rule.

Some stakeholders expressed concern that higher prices due to new standards will increase refurbishing of transformers, which would reduce purchase and shipments of new transformers. (EEI, Public Meeting Transcript, No. 34 at p. 249; NEEA, No. 11 at p. 9; HI, No. 23 at p. 13) NEMA commented that the analysis should consider the replace versus refurbish decision for each considered standard level. (NEMA, No. 13 at pp. 7, 9) ABB commented that it has not observed increased refurbishing with the current regulation since January 1, 2010, but it believes new regulations may well increase the use of rebuilt transformers. (ABB, No. 14 at p. 19) NRECA said that some of its members are already making greater efforts to maintain and refurbish older units rather than purchase costlier new, more efficient units. (NRECA, No. 31 and 36 at p. 4)

To capture the customer response to transformer price increase, DOE estimated the customer price elasticity of demand. Although the general trend of transformer purchases is determined by increases in generation, utilities conceivably exercise some discretion in how much transformer capacity to buy—the amount of ''over-capacity'' to purchase. The ratio of transformer capacity to load varies according to economic considerations, namely the price of transformers, and the income generated by each unit of capacity purchased (essentially the price of electricity). When transformer costs are low, utilities may increase their investment in capacity in order to economically meet future increases in demand, and they will be more likely to do so when returns, indicated by electricity prices, are high. Any decrease in sales induced by an increase in the price of distribution transformers is due to a decrease in this ratio. In DOE's estimation of the purchase price elasticity, it used a logit function to characterize the utilities' response to the price of a unit capacity of transformer. The functional form captures what can be called an average price elasticity of demand with a term to capture the estimation error, which accounts for all other effects. Technically, the price elasticity should therefore account for any decrease in the shipments due to a decision on the customer's part to refurbish transformers as opposed to purchasing a new unit. DOE's approach is described in chapter 9 of the NOPR TSD.

During the negotiated rulemaking, DOE heard from many stakeholders that there is a growing potential for utilities to repair failed transformers and return them to service for less than the cost of a purchasing a new transformer. Some manufacturers commented that if the cost of a new transformer increased by 20 percent utilities may refurbish rather than purchase new equipment to replace failed equipment. (ABB, Public Meeting Transcript, No. 95 at p. 100) DOE received a market potential study from AK Steel stating that the replacement market could represent up to 80 percent of the liquid-immersed market over the next 15 years and that utilities purchasing replacement equipment would consider refurbishing failed units instead of purchasing new equipment. (AK, Public Meeting Transcript, No. 95 at p. 101) DOE received comment from committee members that a small number of municipal utilities were already purchasing refurbished equipment as part of their normal day-to-day operations. (APPA, Public Meeting Transcript, No. 95 at p. 169) On the other hand, PG&E stated that the risks involved with using refurbished equipment (*e.g.,* shorter lifetimes, shorter warrantee, inconsistent equipment quality) give this option limited appeal to larger investor-owned utilities. (PG&E, Public Meeting Transcript, No. 95 at p. 172) DOE acknowledges that uncertainty exists regarding the issue of refurbishing vs. replacement. However, it did not receive data that provided a reasonable basis for changing the analysis used for the NOPR. DOE intends to further investigate this issue for the final rule. Toward that end, DOE request further information that would allow it to quantify the likely extent of refurbishment at different potential standard levels.

2. Efficiency Trends

DOE did not include any base case efficiency trends in its shipments and national energy savings models. AEO forecasts show no long term trend in transmission and distribution losses. DOE estimates that the probability of an increasing efficiency trend and the probability of a decreasing efficiency trend are approximately equal, and therefore used a zero trend in base case efficiency. DOE seeks further comment on its decision to use frozen efficiencies for the analysis period. Specifically, DOE would like comments on additional sources of data on trends in efficiency improvement.

3. Equipment Price Forecast

As noted in section IV.F.2, DOE assumed no change in transformer prices over the 2016–2045 period. In addition, DOE conducted sensitivity analysis using alternative price trends. Based on PPI data for electric power and specialty transformer manufacturing, DOE developed one forecast in which prices decline after 2010, and one in which prices rise. These price trends, and the NPV results from the associated sensitivity cases, are described in Appendix 10–C of the NOPR TSD.

4. Discount Rate

In calculating the NPV, DOE multiplies the net savings in future years by a discount factor to determine their present value. For today's NOPR, DOE estimated the NPV of appliance consumer benefits using both a 3-percent and a 7-percent real discount rate. DOE uses these discount rates in accordance with guidance provided by the Office of Management and Budget (OMB) to Federal agencies on the development of regulatory analysis.[31] The discount rates for the determination of NPV are in contrast to the discount rates used in the LCC analysis, which are designed to reflect a consumer's perspective. The 7-percent real value is an estimate of the average before-tax rate of return to private capital in the U.S. economy. The 3-percent real value represents the ''social rate of time preference,'' which is the rate at which society discounts future consumption flows to their present value.

5. Energy Used in Manufacturing Transformers

FPT stated that DOE should account for the additional energy needed to produce more efficient transformers, such as energy use associated with working with higher-grade core steels. (FPT, No. 27 at p. 4) HI and SC made similar comments. (HI, No. 23 at p. 7; SC, No. 22 at p. 3) In response, DOE notes that EPCA directs DOE to consider the total projected amount of energy, or as applicable, water, savings likely to result directly from the imposition of the standard when determining whether a standard is economically justified. (42 U.S.C. 6295(o)(2)(B)(i)(III)) DOE interprets this to include energy used in the generation, transmission, and distribution of fuels used by appliances or equipment. In addition, DOE is evaluating the full-fuel-cycle measure, which includes the energy consumed in extracting, processing, and transporting primary fuels. DOE's current accounting of primary energy savings and the full-fuel-cycle measure are directly linked to the energy used by appliances or equipment. DOE believes that energy used in manufacturing of appliances or equipment falls outside the boundaries of ''directly'' as intended by EPCA. Thus, DOE did not consider such energy use in the NIA.

H. Customer Subgroup Analysis

In analyzing the potential impacts of new or amended standards, DOE evaluates impacts on identifiable groups (*i.e.,* subgroups) of customers that may be disproportionately affected by a national standard. For this rulemaking, DOE identified purchasers of vault-installed transformers (mainly utilities concentrated in urban areas) as subgroups that could be disproportionately affected, and examined the impact of proposed standards on these groups using the methodology of the LCC and PBP analysis.

Kentucky Association of Electric Cooperatives, Inc. (KAEC) stated that rural electric cooperatives should be analyzed as a customer subgroup in the LCC subgroup analysis because they will face disproportionate costs for any amended efficiency standards. KAEC stated that rural electric cooperatives typically are loaded at only 25 percent, not the 50 percent loading assumed in the test procedure. (KAEC, No. 4 at p. 2) DOE's estimate of average root mean square (RMS) loading for a 50 kVA pad-mounted transformer for the national sample is approximately 35 percent. For rural electric cooperatives DOE used the estimate provided by KAEC to lower the average loading for rural customers, as described in section IV.E of this document.

Several interested parties commented that it is important for DOE to take into consideration the problem that may arise in installing larger transformers in space-constrained situations. HI commented that DOE needs to do more analysis on the size constraints for submersible and vault type transformers. (HI, No. 23 at p. 13) ComEd stated that for street and building vaults, larger transformers potentially could cause severe problems during replacement because of equipment openings, operating clearances, and the loading capacity of floors and elevators. It stated that: (1) Existing building vaults typically have only a few inches of clearance; and (2) larger transformers may not be able to be maneuvered through building hallways or may exceed the weight limitations of building elevators and floors. It added that although a slightly larger transformer would not create a space issue for street/sidewalk vaults, a larger transformer may violate certain company operating clearances inside the vault, and possibly be deemed a safety issue. (ComEd, No. 24 at p. 2) PHI noted that the existing manholes provided for subsurface, subway, and network transformers would have to be enlarged to install a larger unit, which requires time and additional costs. (PHI, No. 26 and 37 at p. 1)

For the NOPR, DOE evaluated vault-installed transformers represented by design lines 4 and 5 as a customer subgroup. DOE examined the impacts of larger transformer volume with regard to costs for vault enlargement. DOE assumed that if the volume of a unit in a standard case is larger than the median volume of transformer designs for the particular design line, a vault modification would be warranted. To estimate the cost, DOE compared the difference in volume between the unit selected in the base case against the unit selected in the standard case, and applied fixed and variable costs. In the 2007 final rule, DOE estimated the fixed cost as $1,740 per transformer and the variable cost as $26 per transformer cubic foot.[32] For today's notice, these costs were adjusted to 2010$ using the chained price index for non-residential construction for power and communications to $1854 per transformer and $28 per transformer cubic foot. DOE considered instances where it may be extremely difficult to modify existing vaults by adding a very high vault replacement cost option to the LCC spreadsheet. Under this option, the fixed cost is $30,000 and the variable cost is $733 per transformer cubic foot.

The customer subgroup analysis is discussed in detail in chapter 11 of the NOPR TSD.

I. Manufacturer Impact Analysis

1. Overview

DOE performed a manufacturer impact analysis (MIA) to estimate the financial impact of amended energy conservation standards on manufacturers of distribution transformers and to calculate the impact of such standards on employment and manufacturing capacity. The MIA has both quantitative and qualitative aspects. The quantitative part of the MIA primarily relies on the Government Regulatory Impact Model (GRIM), an industry cash-flow model with inputs specific to this rulemaking. The key GRIM inputs are data on the industry cost structure, product costs, shipments, and assumptions about markups and conversion expenditures. The key output is the industry net present value (INPV). Different sets of shipment and markup assumptions (scenarios) will produce different results. The qualitative part of the MIA addresses factors such as product characteristics, impacts on particular sub-groups of firms, and important market and product trends. The complete MIA is outlined in Chapter 12 of the NOPR TSD.

[31] OMB Circular A–4 (Sept. 17, 2003), section E, ''Identifying and Measuring Benefits and Costs. Available at: *www.whitehouse.gov/omb/memoranda/m03-21.html.*

[32] See section 7.3.5 of the 2007 final rule TSD, available at *http://www1.eere.energy.gov/buildings/appliance_standards/commercial/pdfs/transformer_fr_tsd/chapter7.pdf*).

DOE conducted the MIA for this rulemaking in three phases. In Phase 1 of the MIA, DOE prepared a profile of the distribution transformer industry, which includes a top-down cost analysis of manufacturers used to derive preliminary financial inputs for the GRIM (*e.g.,* sales general and administration (SG&A) expenses; R&D expenses; and tax rates). DOE used public sources of information, including company Securities and Exchange Commission (SEC) 10–K filings, Moody's company data reports, corporate annual reports, the U.S. Census Bureau's Economic Census, and Hoover's reports.

In Phase 2 of the MIA, DOE prepared an industry cash-flow analysis to quantify the impacts of a new energy conservation standard. In general, more stringent energy conservation standards can affect manufacturer cash flow in three distinct ways: (1) Create a need for increased investment, (2) raise production costs per unit, and (3) alter revenue due to higher per-unit prices and possible changes in sales volumes.

In Phase 3 of the MIA, DOE conducted structured, detailed interviews with a representative cross-section of manufacturers. During these interviews, DOE discussed engineering, manufacturing, procurement, and financial topics to validate assumptions used in the GRIM and to identify key issues or concerns. See section IV.I.4 for a description of the key issues manufacturers raised during the interviews.

Additionally, in Phase 3, DOE evaluates sub-groups of manufacturers that may be disproportionately impacted by standards or that may not be accurately represented by the average cost assumptions use to develop the industry cash-flow analysis. For example, small manufacturers, niche players, or manufacturers with cost structures that largely differ from the industry average could be more negatively affected.

For the MIA, DOE grouped the cash flow results for design lines made by the same sets of manufacturers serving the same markets in order to assess the impacts of amended energy conservation standards with more granularity. DOE separately analyzed the industries of three transformer ''superclasses''—liquid-immersed, medium-voltage dry-type, and low-voltage dry-type—based on differences in the tooling and equipment, product designs, customer types, and characteristics of the markets in which they operate. The Department considered small manufacturers as a separate subgroup because they may be disproportionately affected by standards. DOE applied the small business size standards published by the Small Business Administration (SBA) to determine whether a company is considered a small business 65 FR 30836, 30848 (May 15, 2000), as amended at 65 FR 53533, 53544 (Sept. 5, 2000) and codified at 13 CFR part 121. To be categorized as a small business under NAICS 335311(''Power, Distribution and Specialty Transformer Manufacturing''), a distribution transformer manufacturer and its affiliates may employ a maximum of 750 employees. The 750-employee threshold includes all employees in a business's parent company and any other subsidiaries. Based upon this classification, DOE identified at least 31 small distribution transformer manufacturers that qualify as small businesses. The distribution transformer small manufacturer sub-group is discussed in Chapter 12 of the TSD and in section VI.B.1 of today's notice.

2. Government Regulatory Impact Model

DOE uses the GRIM to quantify the standards-induced changes in cash flow that result in a higher or lower industry value. The GRIM analysis uses a standard, annual cash-flow analysis that incorporates products costs, markups, shipments, and industry financial information as inputs, and models changes in costs, investments, and manufacturer margins that would result from new and amended energy conservation standards. The GRIM spreadsheet uses the inputs to arrive at a series of annual cash flows, beginning with the base year of the analysis, 2011, and continuing to 2045. DOE calculates INPVs by summing the stream of annual discounted cash flows during this period, using a discount rate of 7.4 percent for liquid immersed transformers, 9 percent for medium-voltage dry-type transformers, and 11.1 percent for low-voltage dry-type transformers. The difference in INPV between the base case and a standards case represents the financial impact of the amended standard on manufacturers. DOE's discount rate estimate was derived from industry financials and then modified according to feedback during manufacturer interviews.

DOE typically presents its estimates of industry impacts by groups of the major equipment types served by the same manufacturers. For the distribution transformer industry, DOE presents its estimates of industry impacts for each superclass. The GRIM results are shown in section V.B.2.a. Additional details about the GRIM can be found in Chapter 12 of the TSD.

3. GRIM Key Inputs

a. Manufacturer Production Costs

Manufacturing a higher-efficiency product is typically more expensive than manufacturing a baseline product. The changes in the MPCs of the analyzed products can affect the revenues, gross margins, and cash flow of the industry, making these product cost data key GRIM inputs for DOE's analysis.

During the engineering analysis, DOE used transformer design software to create a database of designs spanning a broad range of efficiencies for each of the representative units. This design software generated a bill of materials. The software also provided information pertaining to the labor necessary to construct the transformer, including the number of turns in the windings and core dimensions, including stack height, which enabled DOE to estimate per unit labor costs. The Department then applied markups to allow for scrap, handling, factory overhead, and non-production costs to estimate the manufacturer selling price.

These designs and their MSPs are subsequently inputted into the LCC customer choice model. For each CSL and within each design line, the LCC model uses a Monte Carlo analysis and criteria described in section F to select a subset of all the potential designs options (and associated MSPs). This subset is meant to represent those designs that would actually be shipped in the market under various standard levels. DOE inputted into the GRIM the weighted average cost of the designs selected by the LCC model and scaled those MPCs to other selected capacities in each design line's KVA range.

b. Base-Case Shipments Forecast

The GRIM estimates manufacturer revenues based on total unit shipment forecasts and the distribution of these values by capacity and design line. Changes in sales volumes and product mix over time can significantly affect manufacturer finances. For this analysis, the GRIM uses the NIA's annual shipment forecasts from 2011 to 2045, the end of the analysis period. See Chapter 9 of the TSD for additional details.

c. Product and Capital Conversion Costs

Amended energy conservation standards will cause manufacturers to incur conversion costs to bring their production facilities and product designs into compliance. For the MIA, DOE classified these conversion costs into two major groups: (1) Product conversion costs and (2) capital conversion costs. Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs necessary to make product designs comply with the new or amended energy conservation standard. Capital conversion costs are investments in property, plant, and equipment necessary to adapt or change existing production facilities such that new product designs can be fabricated and assembled.

Several manufacturers commented on the capital and product conversion costs that would be necessary to meet particular efficiency levels. Power Partners stated that any new standards would require additional retooling and investment (Power Partners, Public Meeting Transcript, No. 19 at p. 1). Howard Industries commented that DOE should consider the full impact of capital investments for higher efficiency designs, such as symmetric core designs, which would require large capital investments and patent fees, and amorphous core designs, which would require large capital investments for additional floor space, laminators, cutters, stackers, encapsulation equipment, and annealing ovens. (Howard Industries, Public Meeting Transcript, No. 23 at p. 10–11) Additionally, Federal Pacific indicated that manufacturers who do not currently have the experience and resources needed to manufacture amorphous cores themselves will have to spend a significant amount of money in certifying amorphous core transformers to the IEEE C57 short circuit requirements if DOE efficiency levels necessitate the use of amorphous steel in core production. (Federal Pacific, Public Meeting Transcript, No. 27 at p. 3)

DOE recognizes manufacturers would incur conversion costs to modify their plants and equipment to produce higher efficiency distribution transformers. DOE explicitly considers these expenditures it in its GRIM analysis; the following describes the department's methodology for estimating potential conversion costs for each TSL.

For capital conversion costs, DOE prepared bottom-up estimates of the costs required to meet standards at each TSL for each design line. To do this, DOE used equipment cost estimates provided by manufacturers and equipment suppliers, an understanding of typical manufacturing processes developed during interviews and in consultation with subject matter experts, and the properties associated with different core and winding materials. Major drivers of capital conversion costs include changes in core steel type (and thickness), core weight, core stack height, and core construction techniques, all of which are interdependent and can vary by efficiency level. DOE uses estimates of the core steel quantities needed by steel type for each TSL, and then most likely core construction techniques, to model the additional equipment the industry would need to meet the efficiencies embodied by each TSL.

For the liquid-immersed sector, conversion costs are entirely driven at each TSL by the need of the industry to expand capacity for amorphous production. Based on interviews with manufacturers and equipment suppliers, DOE assumed an amorphous production line with 1,200 tons of annual capacity would cost $950,000. This figure includes costs associated with an annealing oven, core cutting machine, lacing tables and other miscellaneous equipment. As the increasing stringency of the TSLs drive amorphous adoption, conversion costs increase.

For the low-voltage and medium-voltage dry-type market, DOE took two approaches to estimate capital conversion costs. First, DOE used an industry feedback approach. The Department interviewed manufacturers and industry experts about the capital conversion costs for design lines at increasing efficiency levels, aggregated the conversion cost feedback, and market-shared weighted the feedback to determine likely industry capital conversion costs. For the second approach, DOE performed a bottoms-up analysis of conversion costs based on core steel selections forecasted by the LCC and production equipment costs (a more detailed description of the analysis can be found in chapter 12 of the TSD). The two approaches yielded results with similar orders of magnitude. For those levels that do not require amorphous wound cores, the capital costs are largely driven by the need to modify existing or purchase new core cutting machines and associated equipment and tooling. This need arises as increasingly stringent TSLs require thinner steels, heavier cores, and mitered core construction techniques, all of which slow throughput and reduce existing capacity. At those TSLs where amorphous cores become the dominant steel of choice, DOE used the same amorphous core production line output and cost assumptions as discussed above for the liquid immersed market.

As it relates to product conversion costs, DOE understands the production of amorphous cores requires unique expertise and equipment. For manufacturers without experience with amorphous steel, a standard necessitating the use of the material would require the development or the procurement of the technical expertise necessary to produce cores. Because amorphous steel is extremely thin and brittle after annealing, materials management, safety measures, and design considerations that are not associated with non-amorphous steels would need to be implemented.

For the liquid immersed distribution transformers, because of the industry's relative inexperience with amorphous technology, DOE estimated product conversion costs would equal two times annual industry R&D expenses for those TSLs where a majority of the market would be expected to transition to amorphous material. These one-time expenditures account for the design, engineering, prototyping, and other R&D efforts the industry would have to undertake to move to a predominately amorphous market. At TSL 1, the only TSL which did not show a clear move to amorphous technology, DOE estimated product conversion costs of one times industry annual R&D.

In the low-voltage and medium-voltage dry-type market, DOE aggregated estimates of product conversion costs from manufacturers that were gathered during interviews and scaled those estimates to represent the market share of those not interviewed. Again, for those levels that indicated a clear shift to amorphous (or, in the case of LVDT, potentially wound cores), DOE assumed one-time product conversion costs equal to two times annual industry R&D expenses.

In conclusion, both capital and product conversion costs are key inputs to the GRIM and directly impact the change in INPV that results from new standards. DOE assumed that all conversion-related investments occur between the year of publication of the final rule [33] and the year by which manufacturers must comply with the standard (2016). DOE's estimates of conversion costs can be found in section V.B.2.a of today's notice and a detailed description of the estimation methodology can be found in TSD chapter 12.

d. Standards Case Shipments

As discussed in section F, DOE modeled standard case shipments based on what units the LCC customer choice model selected at each efficiency level. DOE's shipments analysis includes an elasticity factor based on the potential

[33] *I.e.,* 2012.

for transformer purchasers to elect to refurbish rather than replace failed transformers as the purchase price increases. The shipments analysis is discussed in more detail in chapter 9 of the TSD.

e. Markup Scenarios

As discussed above, manufacturer selling prices include direct manufacturing production costs (*i.e.,* labor, material, and overhead estimated in DOE's MPCs) and all non-production costs (*i.e.,* SG&A, R&D, and interest), along with profit. To calculate the MSPs in the GRIM, DOE applied markups to the MPCs estimated in the engineering analysis and selected in the LCC for each design line and efficiency level. Modifying these markups in the standards case yields different sets of impacts on manufacturers. For the MIA, DOE modeled two standards-case markup scenarios to represent the uncertainty regarding the potential impacts on prices and profitability for manufacturers following the implementation of amended energy conservation standards: (1) A preservation of gross margin percentage markup scenario, and (2) a preservation of operating profit markup scenario. These scenarios lead to different markups values, which, when applied to the inputted MPCs, result in varying revenue and cash flow impacts.

Under the preservation of gross margin percentage scenario, DOE applied a single uniform ''gross margin percentage'' markup across all efficiency levels. As production costs increase with efficiency, this scenario implies that the absolute dollar markup will increase as well. Based on publicly available financial information for manufacturers of distribution transformers and comments from manufacturer interviews, DOE assumed the non-production cost markup—which includes SG&A expenses; R&D expenses; interest; and profit—to be 1.25 for distribution transformers. Because this markup scenario assumes that manufacturers would be able to maintain their gross margin percentage markups as production costs increase in response to an energy conservation standard, it represents a high bound to industry profitability under an energy conservation standard.

In the preservation of operating profit scenario, DOE adjusted the manufacturer markups in the GRIM at each TSL to yield approximately the same earnings before interest and taxes in the standards case in the year after the compliance date of the amended standards as in the base case. Under this scenario, as the cost of production and the cost of sales go up, DOE assumes manufacturers are generally required to reduce their markups to a level that maintains base case operating profit in absolute dollars. Therefore, operating margin in percentage terms is reduced between the base case and standards case. This markup scenario represents a low bound to industry profitability under an energy conservation standard.

4. Discussion of Comments

During the April 2011 public meeting, interested parties commented on the assumptions and results of the preliminary TSD. Oral and written comments discussed several topics, including conversion costs, material availability, amorphous steel, and symmetric core technology. DOE addresses these comments below.

a. Material Availability

Manufacturers noted that the availability of raw materials is particularly a concern at higher efficiency levels, where transformer designs would be based upon a very limited selection of steel types. Hammond stated that the supply of high grade steels, such as domain-refined steels, would not be sufficient to meet demand if the efficiency standard forces all designs to use that type of steel. Hammond also stated that shortages could occur if levels are pushed anywhere beyond the current level. (Hammond, Public Meeting Transcript, No. 3 at p. 4 and 6) According to EEI, scarcity of raw materials would be especially problematic if standards are raised beyond CSL 2 for most design lines. Also, EEI noted that if the efficiency levels selected are so high that they can only be met with one or two design options, manufacturers would be faced with limited choices in suppliers and higher costs, and customers would be faced with limited choices in designs and with higher prices. (EEI, Public Meeting Transcript, No. 29 at p. 1 and 4) Furthermore, as noted by KAEC, the transformer industry may not be able to respond to demand under emergency situations if increased efficiency levels reduce the number of options available for core steels and those steels are in limited supply or subject to long lead times. (KAEC, Public Meeting Transcript, No. 4 at p. 3) Southern Company also noted that an improved economy would increase demand for transformers and exacerbate the shortage of core steels necessary to build higher efficiency transformers. (Southern Company, Public Meeting Transcript, No. 22 at p. 1) Many manufacturers expressed concerns about the limited availability of raw materials, especially higher efficiency electrical steels. Power Partners commented that: (1) There is a limited global supply of core steels in grades better than M3, (2) the domestic supply of M2 steel is not enough to support 100 percent of all liquid-immersed transformer production, and (3) grades of grain oriented electrical steel better than M2 (*e.g.,* ZDMH) is in limited supply and only available from a foreign supplier. (Power Partners, Public Meeting Transcript, No. 19 at p. 4) Howard Industries also commented on the limited availability of ZDMH and M2 steel, stating that ZDMH steel is only produced in Japan and that production of M2 steel by AK Steel and Allegheny Ludlum (the two primary suppliers of M2) is unlikely to increase. (Howard Industries, Public Meeting Transcript, No. 23 at p. 10–11)

The use and availability of amorphous steel, in particular, is a major concern in the distribution transformer industry. DOE understands that amorphous steel is currently produced by only two companies in the world (Metglas and AT&M), both of which are foreign-owned and one of which only supplies the Chinese market. Southern Company argued that a standard level that requires the use of amorphous steel could cause domestic suppliers of grain-oriented steel to go out of business or force them to lay off employees. (Southern Company, Public Meeting Transcript, No. 22 at p. 1) Also, Howard Industries commented that, because production in China is not exported, amorphous steel will likely need to be supplied by U.S. manufacturers. (Howard Industries, Public Meeting Transcript, No. 23 at p. 10–11) However, Metglas stated that AT&M (the Chinese amorphous supplier) has announced aggressive expansion in its plants and is expected to export at some point in the future. (Metglas, Public Meeting Transcript, No. 34 at p. 259) Nevertheless, due to the limited current supply of amorphous steel, Federal Pacific suggested that DOE should consider whether the increased demand for amorphous steel from any proposed standard levels could be met by the compliance date. (Federal Pacific, Public Meeting Transcript, No. 27 at p. 2–3)

Manufacturers suggested several analyses which DOE should consider performing in order to determine core steel availability. ABB recommended that DOE should project the consumption of all grades of core steels for each efficiency level in the analysis so that the industry can assess the underlying impact on supply. (ABB, Public Meeting Transcript, No. 14 at p.

17) Schneider Electric recommended that DOE should work with the steel industry to gain insights into core steel availability. (Schneider, Public Meeting Transcript, No. 18 at p. 9) NEMA recommended that DOE should discuss core steel supply with large and small manufacturers, and that DOE should also forecast the supply and cost of steel at each CSL and TSL considered in the analysis. (NEMA, Public Meeting Transcript, No. 13 at p. 7–8) Also, Berman Economics commented that the shape of the material supply curve is more relevant than the current quantity of supply. Once demand increases, the market would respond by supplying more steel, according to Berman Economics. (Berman Economics, Public Meeting Transcript, No. 34 at p. 260)

DOE agrees with comments that standards could shift the mix and quantities of core steels demanded by transformer manufacturers and could alter the market dynamics among core steel and transformer manufacturers. Therefore, DOE interviewed many players in the core steel supply chain. DOE investigated core steel availability with large and small distribution transformers manufacturers, core manufacturers, and steel suppliers. DOE discussed several topics during these interviews, including market capacity for each type of core steel, prospects for expansion, barriers to obtaining those steels, and impacts on competition.

Based on its engineering analysis, DOE recognizes that some high efficiency steels are substantially more cost-effective at higher TSLs than lower-grade or traditional steels. Furthermore, the most stringent TSLs can only be met with certain core steels, typically amorphous, depending on the design line. Based on its interviews and market research, DOE understands these steels are currently produced in limited quantities by a small handful of suppliers, some of which do not produce steels domestically.

To better understand the impact of standards on materials availability, DOE conducted an extensive analysis of the core steel market, as discussed in TSD appendix 3A.

To evaluate the impacts of standards on the core steel market and transformer manufacturers, DOE first estimated the core steel consumption of transformer manufacturers in 2016 (the first year of required compliance with the proposed standard) in the base case and the standards cases. To do this, DOE had to evaluate the designs selected by the LCC customer choice model at each EL for each design line. This model estimated the distribution of designs that would be selected at any given standard level. Key parameters of this sample of selected designs, such as the distribution of core steel types and average core weights by steel type, were critical inputs into the steel demand analysis. DOE found the average core weight of the designs selected for each design line's representative unit at each efficiency level.

Next, the Department used the .75 scaling rule to extrapolate these average core weights to those units forecast to be shipped within a design line but not at the KVA range of the representative unit that is directly analyzed in the engineering and LCC analyses. For example, DOE extrapolated the core weight of the 50 kVA representative unit for DL1 to a 100 kVA unit in DL1. This implicitly assumes that the distribution of core steel types used in transformers remains constant within the kVA range represented by each design line. Although the calculation of core weights for units at the extremes of a kVA range may benefit from an adjusted scaling rule or intermediate design lines, time constraints have limited the extent of the analysis. However, for the most part, the .75 scaling rule is a suitable method for scaling across kVAs.

Using the shipments analysis, which projected kVA demand by design line and capacity, DOE calculated total core steel demand from transformers covered by this rule. While DOE recognizes the core steel market is global in scope, its projections include only core steel used in distribution transformers covered by this rulemaking for use in the U.S. [In response to Southern Company's comment regarding additional demand that may come from an improved economy, DOE notes that the shipment analysis is based on the EIA forecast of economic growth throughout the analysis period, and thus accounts for higher-the-current rates of economic growth.]

In reference to the comments summarized above, based on industry research and the core steel analysis, DOE agrees with Power Partners that domestic steel suppliers do not currently have the capacity to supply the entire distribution transformer market with M2, nor does DOE believe domestic suppliers could cost-effectively produce enough M2 to do so because the nature of silicon steel production limits M2 output to one pound for every four pounds of M3. Due to this manufacturing constraint, if M3 was not able to be used due to standards, steel manufacturers would be unlikely to produce M2 at levels potentially demanded by standards, which could create a tipping point at which the market must move to amorphous by default.

With respect to amorphous demand and capacity, at this time, DOE understands there is only one credible supplier to the U.S. market of high-grade amorphous core steel. (Although there is one notable Chinese supplier with substantial capacity, DOE understands the company has no history of exporting the material and serves only China's rapidly growing domestic market at this time. Despite Metglas' comment above that this supplier is expected to export soon, several manufacturers expressed skepticism at that possibility in interviews and also noted the quality of the steel was poor. At this time, DOE has little reason to believe the company will commence exporting substantial amounts of high quality amorphous steel in the near future.) Based on publically available information, DOE estimates the domestic supplier of amorphous metal has a global capacity of approximately 100,000 metrics tons per year, 40 percent of which is U.S. based. DOE estimates less than 10,000 tons are currently used for covered US transformers. Notably, the company has substantially ramped up capacity in a relatively short time, growing from a 30,000-tons-per-year level in 2005 and lending credence to the notion that its supply can escalate quickly. The amorphous supplier is a subsidiary of a large conglomerate and has commented that it has the financial resources to expand.

While DOE believes the company could substantially grow capacity beyond its current levels in time for a 2016 compliance date, there still exists a significant risk of supply constraints, given the magnitude of the surge in amorphous demand that could potentially be compelled by TSL 2 and above. It is worth noting that this is a global market (indeed, as discussed, DOE estimates less than 10 percent of all amorphous core from this supplier is used in U.S. transformers). Therefore, even if the company could increase capacity substantially, it is unlikely, according to most projections, that demand would remain flat in markets receiving the other 90 percent of this supplier's business.

Beyond potential capacity constraints, DOE is also concerned about the competitive impact—among both steel manufacturers and distribution transformer manufacturers—of a standard that threatened to shift most of the market to amorphous steel. In highly competitive markets, standard economic theory dictates that higher prices would encourage additional suppliers and production to come online, bringing prices back to a long-run equilibrium. In the very long run, that may be true here. However, the highly sophisticated nature of amorphous ribbon production, which is based on extensive know-how gained over years of production and high fixed costs, creates barriers to entry that, while not legal (*i.e.,* patents) in nature, suggest there is a significant risk that there will be no alternative sources of supply by the compliance date or even in the few years beyond it. Therefore, DOE is concerned about the lack of alternative amorphous suppliers and the virtual monopoly supplier that would likely exist in the short term at higher TSLs, particularly given the engineering constraints on the economic production of M2 and very limited supply of ZDMH.

b. Symmetric Core Technology

Several stakeholders commented on the costs that may be associated with the implementation of symmetric core technology. Howard Industries stated that symmetric core designs would require large capital investments and patent fees. (Howard Industries, Public Meeting Transcript, No. 23 at p. 10–11) Conversely, NEEA stated that capital investments for the technology are low according to symmetric core manufacturers (NEEA, Public Meeting Transcript, No. 11 at p. 4). Furthermore, HVOLT argued that, although there may be specific patents with different kinds of construction, patents fundamentally related to core configurations should have expired by now given that symmetric core technology was patented in the 1930s. (HVOLT, Public Meeting Transcript, No. 34 at p. 49)

Symmetric core manufacturers commented on the benefits of symmetric core technology. Hex Tec noted that the equipment used to produce symmetric wound cores is significantly less expensive than flat stacked steel equipment for the same size and the labor production times are lower. (Hex Tec, Public Meeting Transcript, No. 34 at p. 52) Furthermore, according to Hex Tec, intellectual property should not be a concern because there are a number of symmetric core designs available and therefore plenty of variance in design. (Hex Tec, Public Meeting Transcript, No. 34 at p. 49) Hex Tec has also submitted a letter from the Vice President of Research & Development at Metglas which indicates that Hex Tec's core winding machine for amorphous symmetric core designs can be easily scaled for commercialization. (Hex Tec, Public Meeting Transcript, No. 35 at p. 11–14)

DOE did not explicitly analyze symmetric core as a design option for consideration in the engineering. Therefore, symmetric core construction was not considered in the MIA.

c. Patents Related to Amorphous Steel Production

Some manufacturers were concerned about patents on amorphous steel production. ASAP has questioned whether or not there are any patent issues that exist for amorphous manufacturers entering the market. (ASAP, Public Meeting Transcript, No. 34 at p. 262) However, according to Metglas, the basic amorphous patent expired in 1999, so barriers to entry are based more on know-how than on patents. (Metglas, Public Meeting Transcript, No. 34 at p. 262)

Because there are no more patents that create a barrier to entry in the production of amorphous steel, DOE did not consider patents in its analysis of amorphous steel production capacity. However, DOE did consider the technical barriers that exist and accounted for the engineering and R&D investment necessary to begin production.

5. Manufacturer Interviews

DOE interviewed manufacturers representing approximately 65 percent of liquid-immersed transformer sales, 75 percent of medium-voltage dry-type transformer sales, and 30 percent of low-voltage dry-type transformer sales. These interviews were in addition to those DOE conducted as part of the engineering analysis. The information gathered during these interviews enabled DOE to tailor the GRIM to reflect the unique financial characteristics of the distribution transformer industry. All interviews provided information that DOE used to evaluate the impacts of potential new and amended energy conservation standards on manufacturer cash flows, manufacturing capacities, and employment levels.

During the manufacturer interviews, DOE asked manufacturers to describe their major concerns about this rulemaking. The following sections describe the most significant issues identified by manufacturers. DOE also includes additional concerns in chapter 12 of the NOPR TSD.

a. Conversion Costs and Stranded Assets

For manufacturers of distribution transformers, liquid-immersed, medium-voltage dry-type, and low-voltage dry-type, conversion costs and stranded assets are a major concern. All manufacturers stated that efficiency levels that require the use of amorphous steel would sharply increase conversion costs. Due to the thickness and brittleness of amorphous steel, unique production processes and new material handling processes must be applied. Manufacturers noted that they would need to make extensive capital investments in amorphous core production equipment, including core cutting machines, annealing ovens, and lacing tables.

Dry-type manufacturers also stated that a standard that moves the industry to wound cores would also greatly increase conversions costs. Since the vast majority of LVDT and MVDT manufacturers produce stacked cores, a move to wound cores would lead to extensive stranded assets. In some cases, manufacturers may consider purchasing prefabricated cores rather than modifying their facilities to produce wound cores due to the extensive conversion costs.

Additionally, dry-type manufactures stated that a revised standard that does not require amorphous steel or wound core designs could still lead to capital conversion costs. As the standard increases, manufacturers are likely to use higher grade steels for core production. Because high grade steels tend to be thinner, additional Georg machines, core assembly lines and workstations, custom miter cutters, and panel boards may be needed in order to maintain existing throughput levels.

Some manufacturers mentioned that stranded assets may also be an issue when equipment needs to be retired and/or replaced if it cannot be repurposed for higher efficiency designs. DOE accounted for stranded assets in the GRIM.

b. Shortage of Materials

The availability of higher efficiency grain-oriented electrical steels is a key issue for all manufacturers of distribution transformers. Manufacturers stated that there is currently a limited supply of M4, M3, M2, ZDMH, H–0 DR, and SA1 amorphous steels on the market and manufacturers expressed concern that higher standards may increase both demand and prices. Of these steels, M4 and M3 steels are currently the most widely produced, with suppliers such as AK Steel, Allegheny Ludlum, ThyssenKrupp, Nippon, JFE, Wuhan, Novolipetsk, Posco, ArcelorMittal, Orb, Baosteel, Stalproduct, Angang, and Arcelor/Hunan. However, as the grade of grain-oriented electrical steel improves, its availability decreases. M2 is a higher grade than M3 but it is produced by fewer suppliers, such as

AK Steel, Allegheny Ludlum, ThyssenKrupp, Nippon, and JFE. The availability of deep domain-refined steel such as ZDMH, H–0 DR, and SA1 amorphous is even more limited. H–0 DR is only produced by Nippon, JFE, AK Steel, Posco, and Baosteel, and ZDMH is only produced by Nippon. Amorphous steel is only produced by Hitachi (MetGlas) and AT&M, but AT&M only supplies the Chinese market. If efficiency levels are set so high that only amorphous can be used, then domestic manufacturers may be subject to monopolistic pricing from suppliers.

Manufacturers further stated that, in addition to being in limited supply, higher efficiency steels are also: (1) More expensive, (2) subject to tariffs when imported from a foreign supplier, (3) subject to long lead times for both domestic and international suppliers, and (4) difficult to obtain for manufacturers that do not have contracts in place with suppliers. Furthermore, due in part to the major capital investment required to build a steel plant, barriers to entry are high and capacity cannot be easily increased. Transformer manufacturers feel that all these factors contribute to the limited availability of higher efficiency steel.

c. Compliance

Some manufacturers emphasized the importance of compliance and enforcement. According to manufacturers, insufficient enforcement could result in an unfair competitive advantage for some companies who opt not to comply. Manufacturers were particularly concerned about importers of foreign manufactured products. One specific issue is the scope of coverage for low-voltage dry-type transformers, which is currently the scope recommended by NEMA in the 2006 TP1 rulemaking. The market for products inside of scope and the market for products outside of scope are approximately equal in terms of revenue. As a result, if standards increase for products that are in-scope, manufacturers are concerned there would be an increase in demand for products that are out-of-scope and are not be subject to the same compliance burdens. Some of these out-of-scope products are highly inefficient, so if they become more widely used, the energy savings resulting from more efficient in-scope transformers may be significantly offset by the additional energy needed to run less efficient out-of-scope transformers.

d. Effective Date

Manufacturers expressed concerns about the amount of time being provided for the implementation of a possible new standard. Manufacturers indicated that more time is needed to meet a new standard, especially if the standard requires a very high efficiency level. In order to avoid stranding too many assets and materials, sufficient time must be given to manufacturers for the purchase and use of new equipment, development of new designs if needed, and transitioning of customers to new product offerings. Also, some manufacturers stated that standards for low-voltage dry-type transformers, which were not included in the previous 2007 rulemaking, should be on an extended timeline.

e. Emergency Situations

Liquid-immersed transformer manufacturers stated that the ability to obtain waivers during emergency situations is an important issue for them. For example, when a natural disaster occurs, there may be a sharp increase in demand for transformers and manufacturers may not be able to meet DOE's efficiency requirements under these circumstances due to limitations of high efficiency steel availability. In order to adequately supply areas facing such emergency situations, manufacturers requested the ability to obtain waivers so that they can produce transformers as quickly as possible.

Because the TSLs proposed in today's rulemaking can be met using traditional steels, DOE does not anticipate that steel availability during emergency situations will affect manufacturer compliance with the proposed TSLs.

J. Employment Impact Analysis

DOE considers employment impacts in the domestic economy as one factor in selecting a proposed standard. Employment impacts include direct and indirect impacts. Direct employment impacts are any changes in the number of employees of manufacturers of the products subject to standards, their suppliers, and related service firms. The MIA addresses those impacts. Indirect employment impacts are changes in national employment that occur due to the shift in expenditures and capital investment caused by the purchase and operation of more efficient appliances. Indirect employment impacts from standards consist of the jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, due to: (1) Reduced spending by end users on energy; (2) reduced spending on new energy supply by the utility industry; (3) increased consumer spending on the purchase of new products; and (4) the effects of those three factors throughout the economy.

One method for assessing the possible effects on the demand for labor of such shifts in economic activity is to compare sector employment statistics developed by the Labor Department's Bureau of Labor Statistics (BLS). BLS regularly publishes its estimates of the number of jobs per million dollars of economic activity in different sectors of the economy, as well as the jobs created elsewhere in the economy by this same economic activity. Data from BLS indicate that expenditures in the utility sector generally create fewer jobs (both directly and indirectly) than expenditures in other sectors of the economy.[34] There are many reasons for these differences, including wage differences and the fact that the utility sector is more capital-intensive and less labor-intensive than other sectors. Energy conservation standards have the effect of reducing consumer utility bills. Because reduced consumer expenditures for energy likely lead to increased expenditures in other sectors of the economy, the general effect of efficiency standards is to shift economic activity from a less labor-intensive sector (*i.e.,* the utility sector) to more labor-intensive sectors (*e.g.,* the retail and service sectors). Thus, based on the BLS data alone, DOE believes net national employment may increase because of shifts in economic activity resulting from amended standards for transformers.

For the standard levels considered in today's direct final rule, DOE estimated indirect national employment impacts using an input/output model of the U.S. economy called Impact of Sector Energy Technologies version 3.1.1 (ImSET). ImSET is a special-purpose version of the ''U.S. Benchmark National Input-Output'' (I–O) model, which was designed to estimate the national employment and income effects of energy-saving technologies. The ImSET software includes a computer-based I–O model having structural coefficients that characterize economic flows among the 187 sectors. ImSET's national economic I–O structure is based on a 2002 U.S. benchmark table, specially aggregated to the 187 sectors most relevant to industrial, commercial, and residential building energy use. DOE notes that ImSET is not a general equilibrium

[34] See Bureau of Economic Analysis, Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II). Washington, DC. U.S. Department of Commerce, 1992.

forecasting model. Given the relatively small change to expenditures due to energy conservation standards and the resulting small changes to employment, however, DOE believes that the size of any forecast error caused by using ImSET will be small.

For more details on the employment impact analysis, see chapter 13 of the NOPR TSD.

K. Utility Impact Analysis

The utility impact analysis estimates several important effects on the utility industry that would result from the adoption of new or amended standards. For this analysis, DOE used the NEMS–BT model to generate forecasts of electricity consumption, electricity generation by plant type, and electric generating capacity by plant type, that would result from each TSL. DOE obtained the energy savings inputs associated with efficiency improvements to considered products from the NIA. DOE conducts the utility impact analysis as a scenario that departs from the latest *AEO 2011* reference case. In other words, the estimated impacts of a proposed standard are the differences between values forecasted by NEMS–BT and the values in the *AEO 2011* reference case.

As part of the utility impact analysis, DOE used NEMS–BT to assess the impacts on electricity prices of the reduced need for new electric power plants and infrastructure projected to result from the considered standards. In NEMS–BT, changes in power generation infrastructure affect utility revenue requirements, which in turn affect electricity prices. DOE estimated the change in electricity prices projected to result over time from each TSL.

Chapter 14 of the NOPR TSD describes the utility impact analysis.

L. Emissions Analysis

In the emissions analysis, DOE estimated the reduction in power sector emissions of CO_2, NO_X, and Hg from amended energy conservation standards for distribution transformers. DOE used the NEMS–BT computer model, which is run similarly to the AEO NEMS, except that distribution transformer energy use is reduced by the amount of energy saved (by fuel type) due to each TSL. The inputs of national energy savings come from the NIA spreadsheet model, while the output is the forecasted physical emissions. The net benefit of each TSL is the difference between the forecasted emissions estimated by NEMS–BT at each TSL and the *AEO* Reference Case. NEMS–BT tracks CO_2 emissions using a detailed module that provides results with broad coverage of all sectors and inclusion of interactive effects. For today's rule, DOE used the version of NEMS–BT based on *AEO2011,* which incorporated projected effects of all emissions regulations promulgated as of January 31, 2011.

SO_2 emissions from affected electric generating units (EGUs) are subject to nationwide and regional emissions cap and trading programs, and DOE has determined that these programs create uncertainty about the impact of energy conservation standards on SO_2 emissions. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous States and the District of Columbia (DC). SO_2 emissions from 28 eastern States and DC are also limited under the Clean Air Interstate Rule (CAIR, 70 Fed. Reg. 25162 (May 12, 2005)), which created an allowance-based trading program that would gradually replaced the Title IV program in those States and DC. Although CAIR was remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit (DC Circuit), see *North Carolina* v. *EPA,* 550 F.3d 1176 (DC Cir. 2008), it remained in effect temporarily, consistent with the DC Circuit's earlier opinion in *North Carolina* v. *EPA,* 531 F.3d 896 (DC Cir. 2008). On July 6, 2011 EPA issued a replacement for CAIR, the Cross-State Air Pollution Rule. 76 FR 48208 (August 8, 2011). (See *http://www.epa.gov/crossstaterule/*). On December 30, 2011, however, the DC Circuit stayed the new rules while a panel of judges reviews them, and told EPA to continue enforcing CAIR (see *EME Homer City Generation* v. *EPA,* No. 11–1302, Order at *2 (DC Cir. Dec. 30, 2011)). The *AEO 2011* NEMS–BT used for today's NOPR assumes the implementation of CAIR.

The attainment of emissions caps typically is flexible among EGUs and is enforced through the use of emissions allowances and tradable permits. Under existing EPA regulations, any excess SO_2 emissions allowances resulting from the lower electricity demand caused by the imposition of an efficiency standard could be used to permit offsetting increases in SO_2 emissions by any regulated EGU. However, if the standard resulted in a permanent increase in the quantity of unused emissions allowances, there would be an overall reduction in SO_2 emissions from the standards. While there remains some uncertainty about the ultimate effects of efficiency standards on SO_2 emissions covered by the existing cap-and-trade system, the NEMS–BT modeling system that DOE uses to forecast emissions reductions currently indicates that no physical reductions in power sector emissions would occur for SO_2.

As discussed above, the *AEO 2011* NEMS used for today's NOPR assumes the implementation of CAIR, which established a cap on NO_X emissions in 28 eastern States and the District of Columbia. With CAIR in effect, the energy conservation standards for distribution transformers are expected to have little or no physical effect on NO_X emissions in those States covered by CAIR, for the same reasons that they may have little effect on SO_2 emissions. However, the standards would be expected to reduce NO_X emissions in the 22 States not affected by CAIR. For these 22 States, DOE used NEMS–BT to estimate NO_X emissions reductions from the standards considered in today's NOPR.

On December 21, 2011, EPA announced national emissions standards for hazardous air pollutants (NESHAPs) for mercury and certain other pollutants emitted from coal and oil-fired EGUs. (See *http://epa.gov/mats/pdfs/20111216MATSfinal.pdf.*) The NESHAPs do not include a trading program and, as such, DOE's energy conservation standards would likely reduce Hg emissions. For the emissions analysis for this rulemaking, DOE estimated mercury emissions reductions using NEMS–BT based on *AEO2011,* which does not incorporate the NESHAPs. DOE expects that future versions of the NEMS–BT model will reflect the implementation of the NESHAPs.

FPT requested that the DOE perform an emissions analysis for the additional energy required to process higher-grade materials for more efficient core steels. (FPT, No. 27 at p. 4) HI maintained that higher-efficiency transformers will weigh more, which will result in higher air emissions from extra oven energy for annealing and extra energy use for processing raw materials. (HI, No. 23 at p. 12) As discussed in section IV.G.5, DOE did not include the energy used to manufacture transformers in its analysis because EPCA directs DOE to consider the total projected amount of energy savings likely to result directly from the imposition of the standard and DOE interprets this to only include energy used in the generation, transmission, and distribution of fuels used by appliances or equipment. DOE did not include the emissions associated with such energy use for the same reason.

M. Monetizing Carbon Dioxide and Other Emissions Impacts

As part of the development of this proposed rule, DOE considered the estimated monetary benefits likely to result from the reduced emissions of CO_2 and NO_X that are expected to result from each of the considered TSLs. In order to make this calculation similar to the calculation of the NPV of customer benefit, DOE considered the reduced emissions expected to result over the lifetime of products shipped in the forecast period for each TSL. This section summarizes the basis for the monetary values used for each of these emissions and presents the values considered in this rulemaking.

For today's NOPR, DOE is relying on a set of values for the social cost of carbon (SCC) that was developed by an interagency process. A summary of the basis for those values is provided below, and a more detailed description of the methodologies used is provided as an appendix to chapter 16 of the NOPR TSD.

1. Social Cost of Carbon

Under section 1(b)(6) of Executive Order 12866, 58 FR 51735 (Oct. 4, 1993), agencies must, to the extent permitted by law, ''assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.'' The purpose of the SCC estimates presented here is to allow agencies to incorporate the monetized social benefits of reducing CO_2 emissions into cost-benefit analyses of regulatory actions that have small, or ''marginal,'' impacts on cumulative global emissions. The estimates are presented with an acknowledgement of the many uncertainties involved and with a clear understanding that they should be updated over time to reflect increasing knowledge of the science and economics of climate impacts.

As part of the interagency process that developed the SCC estimates, technical experts from numerous agencies met on a regular basis to consider public comments, explore the technical literature in relevant fields, and discuss key model inputs and assumptions. The main objective of this process was to develop a range of SCC values using a defensible set of input assumptions grounded in the existing scientific and economic literatures. In this way, key uncertainties and model differences transparently and consistently inform the range of SCC estimates used in the rulemaking process.

a. Monetizing Carbon Dioxide Emissions

The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services. Estimates of the SCC are provided in dollars per metric ton of carbon dioxide.

When attempting to assess the incremental economic impacts of carbon dioxide emissions, the analyst faces a number of serious challenges. A recent report from the National Research Council[35] points out that any assessment will suffer from uncertainty, speculation, and lack of information about (1) future emissions of greenhouse gases, (2) the effects of past and future emissions on the climate system, (3) the impact of changes in climate on the physical and biological environment, and (4) the translation of these environmental impacts into economic damages. As a result, any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.

Despite the serious limits of both quantification and monetization, SCC estimates can be useful in estimating the social benefits of reducing carbon dioxide emissions. Consistent with the directive quoted above, the purpose of the SCC estimates presented here is to make it possible for agencies to incorporate the social benefits from reducing carbon dioxide emissions into cost-benefit analyses of regulatory actions that have small, or ''marginal,'' impacts on cumulative global emissions. Most Federal regulatory actions can be expected to have marginal impacts on global emissions.

For such policies, the agency can estimate the benefits from reduced (or costs from increased) emissions in any future year by multiplying the change in emissions in that year by the SCC value appropriate for that year. The net present value of the benefits can then be calculated by multiplying each of these future benefits by an appropriate discount factor and summing across all affected years. This approach assumes that the marginal damages from increased emissions are constant for small departures from the baseline emissions path, an approximation that is reasonable for policies that have effects on emissions that are small relative to cumulative global carbon dioxide emissions. For policies that have a large (non-marginal) impact on global cumulative emissions, there is a separate question of whether the SCC is an appropriate tool for calculating the benefits of reduced emissions. This concern is not applicable to this notice, and DOE does not attempt to answer that question here.

At the time of the preparation of this notice, the most recent interagency estimates of the potential global benefits resulting from reduced CO_2 emissions in 2010, expressed in 2010$, were $4.9, $22.3, $36.5, and $67.6 per metric ton avoided. For emissions reductions that occur in later years, these values grow in real terms over time. Additionally, the interagency group determined that a range of values from 7 percent to 23 percent should be used to adjust the global SCC to calculate domestic effects,[36] although preference is given to consideration of the global benefits of reducing CO_2 emissions.

It is important to emphasize that the interagency process is committed to updating these estimates as the science and economic understanding of climate change and its impacts on society improves over time. Specifically, the interagency group has set a preliminary goal of revisiting the SCC values within 2 years or at such time as substantially updated models become available, and to continue to support research in this area. In the meantime, the interagency group will continue to explore the issues raised by this analysis and consider public comments as part of the ongoing interagency process.

b. Social Cost of Carbon Values Used in Past Regulatory Analyses

To date, economic analyses for Federal regulations have used a wide range of values to estimate the benefits associated with reducing carbon dioxide emissions. In the model year 2011 CAFE final rule, the Department of Transportation (DOT) used both a ''domestic'' SCC value of $2 per metric ton of CO_2 and a ''global'' SCC value of $33 per metric ton of CO_2 for 2007 emission reductions (in 2007$), increasing both values at 2.4 percent per year. It also included a sensitivity analysis at $80 per metric ton of CO_2. See *Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011,* 74 FR 14196 (March 30, 2009) (Final Rule); Final Environmental Impact Statement Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years

[35] National Research Council. ''Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.'' National Academies Press: Washington, DC 2009.

[36] It is recognized that this calculation for domestic values is approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time.

2011–2015 at 3–90 (Oct. 2008) (Available at: *http://www.nhtsa.gov/fuel-economy*). A domestic SCC value is meant to reflect the value of damages in the United States resulting from a unit change in carbon dioxide emissions, while a global SCC value is meant to reflect the value of damages worldwide.

A 2008 regulation proposed by DOT assumed a domestic SCC value of $7 per metric ton of CO_2 (in 2006$, with a range of $0 to $14 for sensitivity analysis) for 2011 emission reductions, also increasing at 2.4 percent per year. See *Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015,* 73 FR 24352 (May 2, 2008) (Proposed Rule); Draft Environmental Impact Statement Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015 at 3–58 (June 2008) (Available at: *http://www.nhtsa.gov/fuel-economy*). A regulation for packaged terminal air conditioners and packaged terminal heat pumps finalized by DOE in October of 2008 used a domestic SCC range of $0 to $20 per metric ton CO_2 for 2007 emission reductions (in 2007$). 73 FR 58772, 58814 (Oct. 7, 2008). In addition, EPA's 2008 Advance Notice of Proposed Rulemaking on Regulating Greenhouse Gas Emissions Under the Clean Air Act identified what it described as ''very preliminary'' SCC estimates subject to revision. 73 FR 44354 (July 30, 2008). EPA's global mean values were $68 and $40 per metric ton CO_2 for discount rates of approximately 2 percent and 3 percent, respectively (in 2006$ for 2007 emissions).

In 2009, an interagency process was initiated to offer a preliminary assessment of how best to quantify the benefits from reducing carbon dioxide emissions. To ensure consistency in how benefits are evaluated across agencies, the Administration sought to develop a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions. The interagency group did not undertake any original analysis. Instead, it combined SCC estimates from the existing literature to use as interim values until a more comprehensive analysis could be conducted. The outcome of the preliminary assessment by the interagency group was a set of five interim values: Global SCC estimates for 2007 (in 2006$) of $55, $33, $19, $10, and $5 per ton of CO_2. These interim values represent the first sustained interagency effort within the U.S. government to develop an SCC for use in regulatory analysis. The results of this preliminary effort were presented in several proposed and final rules and were offered for public comment in connection with proposed rules, including the joint EPA–DOT fuel economy and CO_2 tailpipe emission proposed rules.

c. Current Approach and Key Assumptions

Since the release of the interim values, the interagency group reconvened on a regular basis to generate improved SCC estimates, which were considered for this proposed rule. Specifically, the group considered public comments and further explored the technical literature in relevant fields. The interagency group relied on three integrated assessment models (IAMs) commonly used to estimate the SCC: The FUND, DICE, and PAGE models.[37] These models are frequently cited in the peer-reviewed literature and were used in the last assessment of the Intergovernmental Panel on Climate Change. Each model was given equal weight in the SCC values that were developed.

Each model takes a slightly different approach to model how changes in emissions result in changes in economic damages. A key objective of the interagency process was to enable a consistent exploration of the three models while respecting the different approaches to quantifying damages taken by the key modelers in the field. An extensive review of the literature was conducted to select three sets of input parameters for these models: Climate sensitivity, socio-economic and emissions trajectories, and discount rates. A probability distribution for climate sensitivity was specified as an input into all three models. In addition, the interagency group used a range of scenarios for the socio-economic parameters and a range of values for the discount rate. All other model features were left unchanged, relying on the model developers' best estimates and judgments.

The interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models, at discount rates of 2.5 percent, 3 percent, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3-percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution. For emissions (or emission reductions) that occur in later years, these values grow in real terms over time, as depicted in Table IV.7.

TABLE IV.7—SOCIAL COST OF CO_2, 2010–2050

[In 2007 dollars per metric ton]

Year	Discount rate (%)			
	5	3	2.5	3
	Average			
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50.0	100.0
2035	11.2	36.0	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65.0	136.2

[37] The models are described in appendix 15–A of the NOPR TSD.

It is important to recognize that a number of key uncertainties remain, and that current SCC estimates should be treated as provisional and revisable since they will evolve with improved scientific and economic understanding. The interagency group also recognizes that the existing models are imperfect and incomplete. The National Research Council report mentioned above points out that there is tension between the goal of producing quantified estimates of the economic damages from an incremental metric ton of carbon and the limits of existing efforts to model these effects. There are a number of concerns and problems that should be addressed by the research community, including research programs housed in many of the agencies participating in the interagency process to estimate the SCC.

DOE recognizes the uncertainties embedded in the estimates of the SCC used for cost-benefit analyses. As such, DOE and others in the U.S. Government intend to periodically review and reconsider those estimates to reflect increasing knowledge of the science and economics of climate impacts, as well as improvements in modeling. In this context, statements recognizing the limitations of the analysis and calling for further research take on exceptional significance.

In summary, in considering the potential global benefits resulting from reduced CO_2 emissions, DOE used the most recent values identified by the interagency process, adjusted to 2010$ using the GDP price deflator. For each of the four cases specified, the values used for emissions in 2010 were $4.9, $22.3, $36.5, and $67.6 per metric ton avoided (values expressed in 2010$).[38] To monetize the CO_2 emissions reductions expected to result from amended standards for distribution transformers, DOE used the values identified in Table A1 of the ''Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,'' which is reprinted in appendix 16–A of the NOPR TSD, appropriately escalated to 2010$. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the specific discount rate that had been used to obtain the SCC values in each case.

[38] Table A1 presents SCC values through 2050. For DOE's calculation, it derived values after 2050 using the 3-percent per year escalation rate used by the interagency group.

2. Valuation of Other Emissions Reductions

DOE investigated the potential monetary benefit of reduced NO_X emissions from the TSLs it considered. As noted above, new or amended energy conservation standards would reduce NO_X emissions in those 22 States that are not affected by the CAIR. DOE estimated the monetized value of NO_X emissions reductions resulting from each of the TSLs considered for today's NOPR based on environmental damage estimates found in the relevant scientific literature. Available estimates suggest a very wide range of monetary values, ranging from $370 per ton to $3,800 per ton of NO_X from stationary sources, measured in 2001$ (equivalent to a range of $450 to $4,623 per ton in 2010$).[39] In accordance with OMB guidance, DOE conducted two calculations of the monetary benefits derived using each of the economic values used for NO_X, one using a real discount rate of 3 percent and the other using a real discount rate of 7 percent. [40]

DOE is aware of multiple agency efforts to determine the appropriate range of values used in evaluating the potential economic benefits of reduced Hg emissions. DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it once again monetizes Hg in its rulemakings.

N. Discussion of Other Comments

Comments DOE received in response to the preliminary analysis on the soundness and validity of the methodologies and data DOE used are discussed in section IV. Other stakeholder comments in response to the preliminary analysis addressed the burdens and benefits associated with new energy conservation standards. DOE addresses these other stakeholder comments below.

1. Trial Standard Levels

Current standards maintain ''harmonized'' standards across phases, which means that a single-phase transformer must meet the same efficiency standard of its three-phase analog of three times the kVA. DOE is aware of the potential for misapplied standards to shift market demand to segments with relatively less stringent coverage and implanted phase harmonization to guard against incentivizing replacement of three-phase transformers with three smaller single-phase units.

[39] For additional information, refer to U.S. Office of Management and Budget, Office of Information and Regulatory Affairs, 2006 Report to Congress on the Costs and Benefits of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities, Washington, DC

[40] OMB, Circular A–4: Regulatory Analysis (Sept. 17, 2003).

HVOLT asserted that the previous 2007 rulemaking misstated the potential of three-phase distribution transformers early on in the rulemaking. Furthermore, HVOLT commented that, as a result, the final selected TSL for three-phase distribution transformers was low compared to the TSL selected for single-phase transformers. HVOLT believes that this has caused a misperception to the public that three-phase transformers received a less-stringent standard, when it is in fact of equal stringency to the standard for single-phase transformers. HVOLT requested that this point be clarified in the NOPR. (HVOLT, No. 33 at p. 2)

Relative to single-phase designs, DOE understands three-phase transformers to have an efficiency disadvantage related to harmonics and zero-sequence fluxes. That disadvantage happens to be of such a size that efficiency will be similar, all else constant, for transformers with the same power per phase. For example, a 75 kVA three-phase unit should have efficiency similar to that of a 25 kVA single-phase unit designed to similar specifications. During the 2007 rulemaking, DOE created additional TSLs to ''harmonize'' efficiency across phase counts in responses to stakeholder comment that standards should be set thus.

For the NOPR, DOE relaxed the phase harmonization constraint on single-phase efficiency, particularly for LVDT and MVDT equipment classes. DOE believes that market shift will not occur unless standards are dramatically disproportionate.

DOE acknowledges that acceptance of this ''constant efficiency per phase'' principle is not universal and seeks comment on where and why this principle may or may not apply.

Hammond Power Solutions and Howard Industries expressed agreement with DOE's method to develop TSLs. (HPS, No. 3 at p. 5; HI, No. 23 at p. 7) However, ASAP commented that it would like to see the TSL at the minimum LCC point as well as the maximum level that is cost-effective, which typically would fall above the LCC. (ASAP, Pub. Mtg. Tr., No. 34 at p. 127) Furthermore, ASAP encouraged DOE to consider a TSL that retained a variety of core materials as an option, and to include a wide range of TSLs for consideration. (ASAP, Pub. Mtg. Tr., No. 34 at p. 128) ABB commented that DOE should develop a structured methodology that evaluates and ranks each CSL and TSL based on technological feasibility, economic justification, and maximum improvement in energy efficiency. (ABB, No. 14 at pp. 16, 19–20) ABB added that DOE should recognize the risk of inadvertently shifting demand between kVA within the same equipment class, between single-phase and three-phase units within the same product group (*e.g.* MVDT or LVDT), between product groups (*e.g.,* between liquid-immersed and MVDT), and between new product offerings and refurbished transformers. (ABB, No. 14 at pp. 16, 19–20) Edison Electrical Institute requested that DOE provide detailed tables explaining how the CSL numbers in the preliminary analysis relate to the TSL numbers in the NOPR. (EEI, No. 29 at p. 6)

DOE constructs TSLs from efficiency levels (ELs), the NOPR analog of the Preliminary Analysis' CSLs, using several economic factors (*e.g.,* maximum LCC) and technological factors (*e.g.,* maximum LCC where a variety of core materials are available) factors. DOE did not choose a TSL corresponding to minimized LCC savings above the maximum, but does have a TSL corresponding to the CSL above maximum LCC savings that offers increased efficiency. DOE does not use CSLs from the Preliminary Analysis to construct TSLs, but does outline in section V.A the ELs packaged into each TSL. Finally, DOE is concerned about the possibility of inadvertently shifting demand between equipment.

2. Proposed Standards

NRECA and T&DEC cautioned that raising efficiency standards for medium-voltage dry-type transformers would limit a customer's purchase choices and increase costs both for utilities and their customers. They stated that higher efficiency standards would not be economically justified for rural electric cooperatives. (NRECA/T&DEC, No. 31 and No. 36 at pp. 1–2) FPT stated its opposition to new efficiency standards that would limit the choices available to customers to achieve the optimum transformer design for each circumstance. (FPT, No. 27 at p. 1) PHI recommended that DOE not raise efficiency standards for liquid-immersed distribution transformers because they cannot withstand additional increases in weight or dimensions. (PHI, Nos. 26 and 37 at p. 1) FPT commented that, if the efficiency levels for medium-voltage dry-type transformers are increased, the PBP for the cost increase to meet the higher mandated efficiency should be no longer than 3 to 5 years. (FPT, No. 27 at p. 18)

DOE appreciates comment on appropriate standard levels and acknowledges that maintaining availability of equipment offering unique consumer utility is important. DOE believes, however, that it has made an effort to quantify the costs of more efficient equipment to a variety of consumers as well as the costs of additional size and weight.

The Kentucky Association of Electric Cooperatives, Inc. (KAEC) commented that the current minimum efficiency standards for liquid-immersed distribution transformers already represent the maximum energy efficiency that is economically justified, and any higher efficiency level will come at a high cost. (KAEC, No. 4 at pp. 1–2) Power Partners commented that increases to the current minimum efficiency standards are not justified based on the increased costs to manufacturers, customers, and ultimately, consumers. (PP, No. 19 at p. 1) FPT noted that it is not in favor of increasing efficiency standards for dry-type distribution transformers because higher efficiency levels will take away customer choices for the most optimum transformer design. (FPT, No. 27 at pp. 1, 18) Additionally, FPT commented that, because most MVDTs are custom built, they should not be subject to standards. (FPT, No. 27 at pp. 1, 18) Furthermore, HVOLT noted that any standard level should not require a specific design, including materials, configurations and manufacturing methods. HVOLT believes that the 2007 rule reached the limits for many of these considerations, and once the inputs are corrected, the analysis will indicate this result. (HVOLT, No. 33 at p. 3)

Berman Economics suggested that DOE set the efficiency standard at the highest level justified, which appeared to be CSL 4 in the preliminary analysis or CSL 2 at a minimum after adjusting for overpricing. BE suggested that change itself affects manufacturers more than the amount of change because any change in efficiency standards requires manufacturers to re-optimize designs to ensure compliance. (BE, No. 16 at p. 2) Joint comments submitted by ASAP, ACEEE and NRDC noted that DOE's analysis shows that amorphous steel is cost-effective and commented that DOE should propose standards that utilize amorphous steel technology for a portion of the market. They believed that DOE should identify the portion of the market that would be the least disrupted by standards set at an amorphous level, such as small, pad-mounted liquid-immersed transformers (DL1 and DL4). It is their understanding that most of the manufacturers operating in the DL1 and DL4 markets already have amorphous capabilities, and very few smaller manufacturers operate in this market segment. (ASAP/ACEEE/NRDC, No. 28 at pp. 4–5) Alternatively, Power Partners commented that DOE should not set a standard level that requires a core steel above the M3 grade. (PP, No. 19 at p. 4)

DOE conducted several analyses in order to meet its obligation to evaluate the economic justifiability of a proposed standard, notable among them the LCC and PBP Analysis and the NIA. Summaries of those analyses are present in this notice, with more detailed descriptions of the methodology in the TSD. In proposing or setting standards, DOE considers a variety of criteria, including the availability of materials needed to reach a given efficiency. In the case of core steel, DOE has conducted a supply analysis (presented in appendix 3A of the NOPR TSD) examining the ability of the market to supply steel at different efficiency levels and requests comment on the methodology and results of this analysis. The barriers to entry and the potential for limited supply of amorphous steel, and the potential for significant price in the near future, are important qualitative factors that DOE is considering.

The Copper Development Association (CDA) and Pacific Gas & Electric (PG&E) commented that DOE should set standards levels at the highest efficiency that is technologically feasible and economically justified. (CDA, No. 17 at p. 1; PG&E, Pub. Mtg. Tr., No. 34 at pp. 24–25) The American Public Power Association (APPA) noted that the October 2007 final rule for distribution transformers achieved the highest efficiency levels that are economically justified and expressed concern that when efficiency levels gravitate to the highest levels achievable, the cost benefit analysis breaks down as peripheral costs rise. Pole replacements and pad mount replacements–due to larger distribution transformers–also add costs that might not be adequately captured in the DOE analysis. (APPA, No. 21 at p. 2)

HVOLT opined that this rulemaking is a reassessment of the previous distribution transformers rulemaking but with new economic parameters. It asserted that national standards should be doable with known technology, not require an invention, and not put a lot of manufacturers out of business. (HVOLT, Pub. Mtg. Tr., No. 34 at p. 116) NRECA and the Transmission & Distribution Engineering Committee

(T&DEC) together recommended that DOE not raise the efficiency standards for liquid-filled distribution transformers, because the current levels already represent the economically justified maximum efficiency. Both added that many users in rural areas with low transformer loads cannot economically justify the current level. (NRECA/T&DEC, Nos. 31 and 36 at p. 1) Additionally, the added weight and increased dimensions of the higher efficiency distribution transformers would require pole replacement for many cooperatives and other utilities. NRECA/T&DEC opined that when higher efficiency levels are mandated, the result could be less production, less-competitive materials, questionable availability, and reduced competition. (NRECA/T&DEC, Nos. 31 and 36 at p. 3)

FPT noted that if DOE sets higher efficiency standards, it should coordinate with the EPA to reinstitute the Energy Star program for distribution transformers so that manufacturers can use the label to market their products. (FPT, No. 27 at p. 4) FPT also commented that higher efficiency levels based on a specified loading of 35 percent or 50 percent could result in greater losses for applications that operate at higher load factors. FPT provided an example of a NEMA Premium transformer versus a TP1 transformer with an 80-degree temperature rise, indicating that the TP1 transformer with the lower temperature rise could have a greater efficiency at loadings above 50 percent. (FPT, No. 27 at pp. 5–7)

The Kentucky Association of Electric Cooperatives (KAEC) believed that liquid-immersed single-phase standards are adequate and achieve maximum efficiency while being economically justifiable. It believed the biggest efficiency gains have already been made. In addition, KAEC expressed concern that, as a small manufacturer, it would need higher capital investment to meet any increase in efficiency standards, and that its energy savings would be less and payback periods longer because it and other rural electric cooperatives serve fewer customers. (KAEC, Pub. Mtg. Tr., No. 34 at pp. 22–23)

As stated previously, DOE seeks to set the highest energy conservation standards that are technologically feasible, economically justified, and that will result in significant energy savings and appreciates any analysis that would assist DOE in evaluating the appropriate standard using these parameters.

3. Alternative Methods

Mr. Kenneth Harden (HK), a design engineer, offered to DOE a copy of his thesis, which evaluated the impact of federal regulations and operational conditions on the efficiency of low-voltage dry-type distribution transformers, and provided recommendations to optimize future rulemakings certifying the energy efficiency of low-voltage dry-type distribution transformers. It also recommended the specification of low-voltage dry-type distribution transformers and the design of transformers for industrial power networks. (HK, No. 12 at p. 1)

DOE appreciates Mr. Harden's submission and would welcome a meeting to discuss some of the thoughts he has put forth on the rulemaking process in general and on distribution transformers in particular.

4. Labeling

Both NEMA and FPT recommended that DOE establish a uniform approach for how to mark a distribution transformer nameplate to indicate compliance with the applicable energy conservation standard in 10 CFR 431.196. (FPT, No. 27 at p. 20; NEMA, No. 13 at p. 9) NEMA proposed the following: ''DOE 10 CFR PART 431 COMPLIANT.'' (NEMA, No. 13 at p. 9)

DOE appreciates the comments regarding labeling and will take it under consideration as it continues to explore appropriate requirements for certification, compliance, enforcement and how labeling may fit into those processes. Certification requirements for distribution transformers can be found in 10 CFR 429.47.

5. Imported Units

NEMA commented that, although covered non-compliant products that are imported for export must be marked as such, U.S. Customs and Border Protection will likely have difficulty determining which products are covered, and whether a covered product is compliant, other than those marked for export. (NEMA, No. 13 at p. 9)

DOE notes that it is the responsibility of the importer, and not United States Customs, to establish compliance just as any manufacturer would. DOE welcomes further comment and evidence that can suggest imported transformers are failing to meet standards.

V. Analytical Results and Conclusions

A. Trial Standard Levels

DOE analyzed the benefits and burdens of the TSLs developed for today's proposed rule. DOE examined seven TSLs for liquid-immersed distribution transformers, six TSLs for low-voltage, dry-type distribution transformers, and five TSLs for medium-voltage dry-type distribution transformers. Table V.1 through Table V.3 present the TSLs analyzed and the corresponding efficiency level for the representative unit in each transformer design line. For other capacities in each design line, the corresponding efficiencies for each TSL are given in appendix 8–B in the NOPR TSD. The baseline in the tables is equal to the current energy conservation standard.

For liquid-immersed distribution transformers, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents an increase in efficiency where a diversity of electrical steels are cost-competitive and economically feasible for all design lines; TSL 2 represents EL1 for all design lines; TSL 3 represents the maximum efficiency level achievable with M3 core steel; TSL 4 represents the maximum NPV with 7 percent discounting; TSL 5 represents EL 3 for all design lines; TSL 6 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 7 represents the maximum technologically feasible level (max tech).

For low-voltage, dry-type distribution transformers, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents the maximum efficiency level achievable with M6 core steel; TSL 2 represents NEMA premium levels; TSL 3 represents the maximum EL achievable using butt-lap miter core manufacturing for single-phase distribution transformers, and full miter core manufacturing for three-phase distribution transformers; TSL 4 represents the maximum NPV with 7 percent discounting; TSL 5 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 6 represents the maximum technologically feasible level (max tech).

For medium-voltage, dry-type distribution transformers, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents EL1 for all design lines; TSL 2 represents an increase in efficiency where a diversity of electrical steels are cost-competitive and economically feasible for all design lines; TSL 3 represents the maximum NPV with 7 percent discounting; TSL 4 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 5 represents the maximum technologically feasible level (max tech).

TABLE V.1—EFFICIENCY VALUES OF THE TRIAL STANDARD LEVELS FOR LIQUID-IMMERSED TRANSFORMERS BY DESIGN LINE

[In percent]

Design line	Baseline	TSL						
		1	2	3	4	5	6	7
1	99.08	99.16	99.16	99.16	99.22	99.25	99.31	99.50
2	98.91	98.91	99.00	99.00	99.07	99.11	99.18	99.41
3	99.42	99.48	99.48	99.51	99.57	99.54	99.61	99.73
4	99.08	99.16	99.16	99.16	99.22	99.25	99.31	99.60
5	99.42	99.48	99.48	99.51	99.57	99.54	99.61	99.69

TABLE V.2—EFFICIENCY VALUES OF THE TRIAL STANDARD LEVELS FOR LOW-VOLTAGE DRY-TYPE TRANSFORMERS BY DESIGN LINE

[In percent]

Design line	Baseline	TSL					
		1	2	3	4	5	6
6	98.00	98.00	98.60	98.80	99.17	99.17	99.44
7	98.00	98.47	98.60	98.80	99.17	99.17	99.44
8	98.60	99.02	99.02	99.25	99.44	99.58	99.58

TABLE V.3—EFFICIENCY VALUES OF THE TRIAL STANDARD LEVELS FOR MEDIUM-VOLTAGE DRY-TYPE TRANSFORMERS BY DESIGN LINE

[In percent]

Design line	Baseline	TSL				
		1	2	3	4	5
9	98.82	98.93	98.93	99.04	99.04	99.55
10	99.22	99.29	99.37	99.37	99.37	99.63
11	98.67	98.81	98.81	99.13	99.13	99.50
12	99.12	99.21	99.30	99.46	99.46	99.63
13A	98.63	98.69	98.69	99.04	99.04	99.45
13B	99.15	99.19	99.28	99.45	99.45	99.52

B. Economic Justification and Energy Savings

1. Economic Impacts on Customers

a. Life-Cycle Cost and Payback Period

To evaluate the net economic impact of standards on transformer customers, DOE conducted LCC and PBP analyses for each TSL. In general, a higher-efficiency product would affect customers in two ways: (1) Annual operating expense would decrease; and (2) purchase price would increase. Section III.F.2 of this notice discusses the inputs DOE used for calculating the LCC and PBP. The LCC and PBP results are calculated from transformer cost and efficiency data that are modeled in the engineering analysis (section IV.C). During the negotiated rulemaking, DOE presented separate transformer cost data based on 2010 and 2011 material prices to the committee members. DOE conducted its LCC and PBP analysis utilizing both the 2010 and 2011 material price cost data. The average results of these two analyses are presented here.

For each design line, the key outputs of the LCC analysis are a mean LCC savings and a median PBP relative to the base case, as well as the fraction of customers for which the LCC will decrease (net benefit), increase (net cost), or exhibit no change (no impact) relative to the base-case product forecast. No impacts occur when the product efficiencies of the base-case forecast already equal or exceed the efficiency at a given TSL. Table V.4 through Table V.17 show the key results for each transformer design line.

TABLE V.4—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 1 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	99.16	99.16	99.16	99.22	99.25	99.31	99.50
Transformers with Net LCC Cost (%)	57.9	57.9	57.9	4.8	4.8	8.0	55.4

TABLE V.4—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 1 REPRESENTATIVE UNIT—Continued

	Trial standard level						
	1	2	3	4	5	6	7
Transformers with Net LCC Benefit (%)	41.8	41.8	41.8	95.0	95.0	92.0	44.6
Transformers with No Change in LCC (%)	0.2	0.2	0.2	0.2	0.2	0.0	0.0
Mean LCC Savings ($)	36	36	36	641	641	532	50
Median PBP (Years)	20.2	20.2	20.2	7.9	7.9	10.0	19.2

TABLE V.5—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 2 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	98.91	99.00	99.00	99.07	99.11	99.18	99.41
Transformers with Net LCC Cost (%)	0.0	14.2	14.2	9.8	11.2	15.8	80.2
Transformers with Net LCC Benefit (%)	0.0	85.8	85.8	90.2	88.8	84.3	19.8
Transformers with No Change in LCC (%)	100.0	0.0	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	0	309	309	338	300	250	−736
Median PBP (Years)	0.0	6.9	6.9	8.0	9.5	11.5	24.3

TABLE V.6—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 3 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	99.48	99.48	99.51	99.57	99.54	99.61	99.73
Transformers with Net LCC Cost (%)	15.7	15.7	11.2	4.0	5.3	3.9	25.1
Transformers with Net LCC Benefit (%)	83.0	83.0	87.7	96.0	94.6	96.1	74.9
Transformers with No Change in LCC (%)	1.4	1.4	1.2	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	2,413	2,413	3,831	5,591	5,245	6,531	4,135
Median PBP (Years)	6.3	6.3	4.0	4.7	4.6	5.2	13.3

TABLE V.7—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 4 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	99.16	99.16	99.16	99.22	99.25	99.31	99.60
Transformers with Net LCC Cost (%)	6.0	6.0	6.0	1.9	1.9	1.9	31.1
Transformers with Net LCC Benefit (%)	93.5	93.5	93.5	97.5	97.5	97.6	63.9
Transformers with No Change in LCC (%)	0.6	0.6	0.6	0.6	0.6	0.6	0.0
Mean LCC Savings ($)	862	862	862	3,356	3,356	3,362	1,274
Median PBP (Years)	5.0	5.0	5.0	4.1	4.1	4.1	14.6

TABLE V.8—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 5 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	99.48	99.48	99.51	99.57	99.54	99.61	99.69
Transformers with Net LCC Cost (%)	19.1	19.1	13.2	7.8	10.4	7.9	39.9
Transformers with Net LCC Benefit (%)	80.6	80.6	86.8	92.2	89.6	92.1	60.1

TABLE V.8—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 5 REPRESENTATIVE UNIT—Continued

	Trial standard level						
	1	2	3	4	5	6	7
Transformers with No Change in LCC (%)	0.4	0.4	0.1	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	7,787	7,787	10,288	12,513	11,395	12,746	3,626
Median PBP (Years)	4.0	4.0	4.2	6.3	5.7	8.3	16.9

TABLE V.9—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 6 REPRESENTATIVE UNIT

	Trial standard level					
	1	2	3	4	5	6
Efficiency (%)	98.00	98.60	98.93	99.17	99.17	99.44
Transformers with Net Increase in LCC (%)	0.0	71.5	17.6	36.2	36.2	93.4
Transformers with Net LCC Savings (%)	0.0	28.5	82.4	63.8	63.8	6.6
Transformers with No Impact on LCC (%)	100.0	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	0	−125	335	187	187	−881
Median PBP (Years)	0.0	24.7	13.0	16.3	16.3	32.4

TABLE V.10—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 7 REPRESENTATIVE UNIT

	Trial standard level					
	1	2	3	4	5	6
Efficiency (%)	98.47	98.60	98.80	99.17	99.17	99.44
Transformers with Net Increase in LCC (%)	1.8	1.8	2.0	3.7	3.7	46.4
Transformers with Net LCC Savings (%)	98.2	98.2	98.0	96.3	96.3	53.6
Transformers with No Impact on LCC (%)	0.0	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	1,714	1,714	1,793	2,270	2,270	270
Median PBP (Years)	4.5	4.5	4.7	6.9	6.9	18.1

TABLE V.11—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 8 REPRESENTATIVE UNIT

	Trial standard level					
	1	2	3	4	5	6
Efficiency (%)	99.02	99.02	99.25	99.44	99.58	99.58
Transformers with Net Increase in LCC (%)	5.2	5.2	15.3	10.5	78.5	78.5
Transformers with Net LCC Savings (%)	94.8	94.8	84.7	89.5	21.5	21.5
Transformers with No Impact on LCC (%)	0.0	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	2,476	2,476	2,625	4,145	−2,812	−2,812
Median PBP (Years)	8.4	8.4	12.3	11.0	24.5	24.5

TABLE V.12—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 9 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	98.93	98.93	99.04	99.04	99.55
Transformers with Net Increase in LCC (%)	3.4	3.4	5.7	5.7	53.4
Transformers with Net LCC Savings (%)	83.4	83.4	94.3	94.3	46.6
Transformers with No Impact on LCC (%)	13.3	13.3	0.0	0.0	0.0
Mean LCC Savings ($)	849	849	1,659	1,659	237
Median PBP (Years)	2.6	2.6	6.2	6.2	19.1

TABLE V.13—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 10 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	99.29	99.37	99.37	99.37	99.63
Transformers with Net Increase in LCC (%)	0.7	16.7	16.7	16.7	84.8

TABLE V.13—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 10 REPRESENTATIVE UNIT—Continued

	Trial standard level				
	1	2	3	4	5
Transformers with Net LCC Savings (%)	98.8	83.3	83.3	83.3	15.2
Transformers with No Impact on LCC (%)	0.5	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	4,509	4,791	4,791	4,791	−12,756
Median PBP (Years)	1.1	8.8	8.8	8.8	28.4

TABLE V.14—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 11 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	98.81	98.81	99.13	99.13	99.50
Transformers with Net Increase in LCC (%)	20.6	20.6	25.7	25.7	76.1
Transformers with Net LCC Savings (%)	79.4	79.4	74.3	74.3	23.9
Transformers with No Impact on LCC (%)	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	1,043	1,043	2,000	2,000	−3160
Median PBP (Years)	10.7	10.7	14.1	14.1	24.5

TABLE V.15—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 12 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	99.21	99.30	99.46	99.46	99.63
Transformers with Net Increase in LCC (%)	6.7	7.8	18.1	18.1	81.1
Transformers with Net LCC Savings (%)	93.3	92.2	81.9	81.9	18.9
Transformers with No Impact on LCC (%)	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	4,518	6,934	8,860	8,860	−12,420
Median PBP (Years)	6.3	9.0	13.0	13.0	25.9

TABLE V.16—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 13A REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	98.69	98.69	99.04	99.04	99.45
Transformers with Net Increase in LCC (%)	52.2	52.2	64.4	64.4	97.1
Transformers with Net LCC Savings (%)	47.8	47.8	35.6	35.6	2.9
Transformers with No Impact on LCC (%)	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	25	25	−846	−846	−11,077
Median PBP (Years)	16.5	16.5	21.7	21.7	37.1

TABLE V.17—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 13B REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	99.19	99.28	99.45	99.45	99.52
Transformers with Net Increase in LCC (%)	28.5	26.3	52.7	52.7	67.2
Transformers with Net LCC Savings (%)	71.3	73.7	47.3	47.3	32.8
Transformers with No Impact on LCC (%)	0.2	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	2,733	4,709	384	384	−5,407
Median PBP (Years)	4.6	12.5	19.3	19.3	21.9

b. Customer Subgroup Analysis

DOE estimated customer subgroup impacts by determining the LCC impacts of the distribution transformer TSLs on purchasers of vault-installed transformers (primarily urban utilities). DOE included only the liquid-immersed design lines in this analysis, since those types account for more than ninety percent of the transformers purchased by electric utilities. Table V.18 shows the mean LCC savings at each TSL for this customer subgroup.

Chapter 11 of the NOPR TSD explains DOE's method for conducting the customer subgroup analysis and presents the detailed results of that analysis.

TABLE V.18—COMPARISON OF MEAN LIFE-CYCLE COST SAVINGS FOR LIQUID-IMMERSED TRANSFORMERS PURCHASED BY CONSUMER SUBGROUPS

[2010$]

Design line	Trial standard level						
	1	2	3	4	5	6	7
Medium Vault Replacement Subgroup							
4	−422	−422	−422	106	106	113	−2,358
5	1,062	1,062	3,203	4,689	3,854	4,270	−5,996
All Customers							
4	862	862	862	3,356	3,356	3,362	1,274
5	7,787	7,787	10,288	12,513	11,395	12,746	3626

c. Rebuttable-Presumption Payback

As discussed above, EPCA establishes a rebuttable presumption that an energy conservation standard is economically justified if the increased purchase cost for a product that meets the standard is less than three times the value of the first-year energy savings resulting from the standard. (42 U.S.C. 6295(o)(2)(B)(iii), 6316(a)) DOE calculated a rebuttable-presumption PBP for each TSL to determine whether DOE could presume that a standard at that level is economically justified. Table V.19 shows the rebuttable-presumption PBPs for the considered TSLs. Because only a single, average value is necessary for establishing the rebuttable-presumption PBP, DOE used discrete values rather than distributions for its input values. As required by EPCA, DOE based the calculations on the assumptions in the DOE test procedure for distribution transformers. (42 U.S.C. 6295(o)(2)(B)(iii), 6316(a)) As a result, DOE calculated a single rebuttable-presumption payback value, and not a distribution of PBPs, for each TSL.

TABLE V.19—REBUTTABLE-PRESUMPTION PAYBACK PERIODS (YEARS) FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Design line	Rated capacity (kVA)	Trial standard level						
		1	2	3	4	5	6	7
1	50	17.1	17.1	17.1	8.3	8.3	10.2	16.3
2	25	0.0	9.5	9.5	9.9	11.0	12.5	21.3
3	500	5.8	5.8	4.5	4.9	4.9	5.2	11.9
4	150	4.7	4.7	4.7	3.9	3.9	4.0	13.5
5	1500	4.3	4.3	4.2	5.9	5.5	7.5	15.2

TABLE V.20—REBUTTABLE-PRESUMPTION PAYBACK PERIODS (YEARS) FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Design line	Rated capacity (kVA)	Trial standard level					
		1	2	3	4	5	6
6	25	0.0	15.9	13.0	15.0	15.0	26.5
7	75	4.2	4.2	4.4	6.4	6.4	14.9
8	300	6.8	6.8	10.4	9.7	20.2	20.2

TABLE V.21—REBUTTABLE-PRESUMPTION PAYBACK PERIODS (YEARS) FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Design line	Rated capacity (kVA)	Trial standard level				
		1	2	3	4	5
9	300	1.9	1.9	4.6	4.6	15.5
10	1,500	1.9	5.7	5.7	5.7	21.8
11	300	9.5	9.5	13.0	13.0	18.8
12	1,500	5.5	7.44	12.0	12.0	20.3
13A	300	11.9	11.9	22.2	22.2	28.9
13B	2,000	5.2	11.1	19.1	19.1	19.4

DOE believes that the rebuttable-presumption PBP criterion (*i.e.,* a limited PBP) is not sufficient for determining economic justification. Therefore, DOE has considered a full range of impacts, including those to customers, manufacturers, the Nation, and the environment. Section V.C provides a complete discussion of how DOE considered the range of impacts to select its proposed standards.

2. Economic Impact on Manufacturers

DOE performed a MIA to estimate the impact of amended energy conservation standards on manufacturers of distribution transformers. The section below describes the expected impacts on manufacturers at each TSL. Chapter 12 of the TSD explains the analysis in further detail.

a. Industry Cash-Flow Analysis Results

The tables below depict the financial impacts (represented by changes in INPV) of amended energy standards on manufacturers as well as the conversion costs that DOE estimates manufacturers would incur at each TSL. The effect of amended standards on INPV was analyzed separately for each type of distribution transformer manufacturer: Liquid-immersed, medium-voltage dry-type, and low-voltage dry-type. To evaluate the range of cash flow impacts on the distribution transformer industry, DOE modeled two different scenarios using different assumptions for markups that correspond to the range of anticipated market responses to new and amended standards. A full description of these scenarios and their results can be found in chapter 12 of the NOPR TSD.

To assess the lower end of the range of potential impacts, DOE modeled the preservation of operating profit markup scenario, which assumes that manufacturers would be able to earn the same operating margin in absolute dollars in the standards case as in the base case. To assess the higher end of the range of potential impacts, DOE modeled a preservation of gross margin percentage markup scenario in which a uniform ''gross margin percentage'' markup is applied across all efficiency levels. In this scenario, DOE assumed that a manufacturer's absolute dollar markup would increase as production costs increase in the standards case.

The set of results below shows two tables of INPV impacts for each of the three types of distribution transformer manufacturers: The first table reflects the lower bound of impacts and the second represents the upper bound.

In the discussion that follows the tables, DOE also discusses the difference in cash flow between the base case and the standards case in the year before the compliance date for new and amended energy conservation standards. This figure represents how large the required conversion costs are relative to the cash flow generated by the industry in the absence of new and amended energy conservation standards.

TABLE V.22—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT MARKUP SCENARIO

	Units	Base case	Trial standard level						
			1	2	3	4	5	6	7
INPV	2011$ M	625.1	585.5	532.1	523.8	461.0	451.2	427.5	297.9
Change in INPV	2011$ M		(39.6)	(92.9)	(101.2)	(164.0)	(173.8)	(197.6)	(327.2)
	%		(6.3)	(14.9)	(16.2)	(26.2)	(27.8)	(31.6)	(52.3)
Capital Conversion Costs	2011$ M		26.3	64.9	67.6	98.5	100.4	105.6	128.2
Product Conversion Costs	2011$ M		27.6	46.8	57.5	93.7	93.7	93.7	93.7
Total Conversion Costs	2011$ M		53.9	111.7	125.1	192.1	194.1	199.3	221.8

* **Note:** Parentheses indicate negative values.

TABLE V.23—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE MARKUP

	Units	Base case	Trial standard level						
			1	2	3	4	5	6	7
INPV	2011$ M	625.1	614.7	583.4	577.5	551.6	537.1	547.6	673.0
Change in INPV	2011$ M		(10.4)	(41.7)	(47.6)	(73.5)	(88.0)	(77.5)	48.0
	%		(1.7)	(6.7)	(7.6)	(11.8)	(14.1)	(12.4)	7.7
Capital Conversion Costs	2011$ M		26.3	64.9	67.6	98.5	100.4	105.6	128.2
Product Conversion Costs	2011$ M		27.6	46.8	57.5	93.7	93.7	93.7	93.7
Total Conversion Costs	2011$ M		53.9	111.7	125.1	192.1	194.1	199.3	221.8

At TSL 1, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$39.6 million to −$10.4 million, corresponding to a change in INPV of −6.3 percent to −1.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 60.1 percent to $15.8 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

While TSL 1 can be met with traditional steels, including M3, in all design lines, amorphous core transformers will be incrementally more competitive on a first cost basis, likely inducing some or many manufacturers to gradually build amorphous steel transformer production capacity. Because the production process for amorphous cores is entirely separate from that of silicon steel cores, large investments in new capital, including new core cutting equipment and annealing ovens will be required. Additionally, a great deal of testing, prototyping, design and manufacturing engineering resources will be required because most manufacturers have relatively little experience, if any, with amorphous steel transformers. These capital and production conversion expenses lead to a reduction in cash flow in the years preceding the standard. In the lower-bound scenario, DOE assumes manufacturers can only maintain annual operating profit in the standards case. Therefore, these conversion investments, and manufacturers' higher working capital needs associated with more expensive transformers, drain cash flow and lead to a greater reduction in INPV, when compared to the upper-bound scenario. In the upper bound scenario, DOE assumes manufacturers will be able to fully mark up and pass the higher product costs, leading to higher operating income. This higher operating income is essentially offset on a cash flow basis by the conversion costs and the increase in working capital requirements, leading to a negligible change in INPV at TSL1 in the upper-bound scenario.

At TSL 2, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$92.9 million to −$41.7 million, corresponding to a change in INPV of −14.9 percent to −6.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 122.7 percent to −$9 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

TSL 2 requires the same efficiency levels as TSL 1, except for DL 2, which is increased from baseline to EL1. EL1, as opposed to the baseline efficiency, could induce manufacturers to build more amorphous capacity, when compared to TSL 1, because amorphous transformers become incremental more cost competitive. Because DL2 represents the largest share of core steel usage of all design lines, this has a significant impact on investments. There are more severe impacts on industry in the lower-bound profitability scenario when these greater one-time cash outlays are coupled with slight margin pressure. In the high-profitability scenario, manufacturers are able to maintain gross margins, mitigating the adverse cash flow impacts of the increased investment in working capital (associated with more expensive transformers).

At TSL 3, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$101.2 million to −$47.6 million, corresponding to a change in INPV of −16.2 percent to −7.6 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 135.2 percent to −$13.9 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

TSL 3 results are similar to TSL 2 results because the efficiency levels are the same except for DL3 and DL5, which each increase to EL 2 under TSL 3. The increase in stringency makes more amorphous core transformers slightly more cost competitive in these DLs, likely increasing amorphous transformer capacity needs, all other things being equal, and driving more investment to meet the standards.

At TSL 4, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$164 million to −$73.5 million, corresponding to a change in INPV of −26.2 percent to −11.8 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 202 percent to −$40.3 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

During interviews, manufacturers expressed differing views on whether the efficiency levels embodied in TSL 4 would shift the market away from silicon steels entirely. Because DL3 and DL5 must meet EL4 at this TSL, DOE expects the majority of the market would shift to amorphous core transformers at TSL 4 and above. Even assuming a sufficient supply of amorphous steel were available, TSL 4 and above would require a dramatic build up in amorphous core transformer production capacity. DOE believes this wholesale transition away from silicon steels could seriously disrupt the market, drive small businesses to either source their cores or exit the market, and lead even large businesses to consider moving production offshore or exiting the market altogether. The negative impacts are driven by the large conversion costs associated with new amorphous production lines and stranded assets of manufacturers' existing silicon steel transformer production capacity. If the higher first costs at TSL 4 drive more utilities to refurbish rather than replace failed transformers, a scenario many manufacturers predicted at the efficiency levels and prices embodied in TSL 4, reduced transformer sales could cause further declines in INPV.

At TSL 5, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$173.8 million to −$88 million, or a change in INPV of −27.8 percent to −14.1 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 230.8 percent to −$51.7 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

TSL5 would likely shift the entire market to amorphous core transformers, leading to even greater investment needs than TSL4, driving the adverse impacts discussed above.

At TSL 6, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$197.6 million to −$77.5 million, corresponding to a change in INPV of −31.6 percent to −12.4 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 241.5 percent to −$55.9 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

The impacts at TSL 6 are similar to those DOE expects at TSL 5, except that slightly more amorphous core production capacity will be needed because TSL 6-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 6 compared to TSL 5.

At TSL 7, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$327.2 million to $48 million, corresponding to a change in INPV of -52.3 percent to 7.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 267.2 percent to -$66 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

The impacts at TSL 7 are similar to those DOE expects at TSL 6, except that slightly more amorphous core production capacity will be needed because TSL 6-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 7 compared to TSL 6, incrementally reducing industry value.

TABLE V.24—MANUFACTURER IMPACT ANALYSIS LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT MARKUP SCENARIO

	Units	Base case	Trial standard level					
			1	2	3	4	5	6
INPV	2011$M	219.5	202.7	199.9	192.8	173.4	164.2	136.4
Change in INPV	2011$M		(16.8)	(19.6)	(26.7)	(46.1)	(55.3)	(83.1)
	%		(7.7)	(8.9)	(12.2)	(21.0)	(25.2)	(37.9)
Capital Conversion Costs	2011$M		5.1	7.4	11.4	23.8	23.8	23.8
Product Conversion Costs	2011$M		2.9	3.8	5.0	8.0	8.0	8.0
Total Conversion Costs	2011$M		8.0	11.1	16.4	31.8	31.8	31.8

* **Note:** Parentheses indicate negative values.

TABLE V.25—MANUFACTURER IMPACT ANALYSIS LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE MARKUP SCENARIO

	Units	Base Case	Trial Standard Level					
			1	2	3	4	5	6
INPV	2011$M	219.5	236.4	234.6	239.6	250.4	263.4	321.5
Change in INPV	2011$M		16.9	15.0	20.1	30.9	43.9	101.9
	%		7.7	6.8	9.1	14.1	20.0	46.4
Capital Conversion Costs	2011$M		5.1	7.4	11.4	23.8	23.8	23.8
Product Conversion Costs	2011$M		2.9	3.8	5.0	8.0	8.0	8.0
Total Conversion Costs	2011$M		8.0	11.1	16.4	31.8	31.8	31.8

* **Note:** Parentheses indicate negative values.

At TSL 1, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$16.8 million to $16.9 million, corresponding to a change in INPV of −7.7 percent to 7.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 26.1 percent to $10.2 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL 1 provides many design paths for manufacturers to comply. DOE's engineering analysis indicates manufacturers can continue to use the low-capital butt-lap core designs, meaning investment in mitering or wound core capability is not necessary. Manufacturers can use higher-quality grain oriented steels in butt-lap designs to meet TSL1, source some or all cores, or invest in modified mitering capability.

At TSL 2, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$19.6 million to $15 million, corresponding to a change in INPV of −8.9 percent to 6.8 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 37.4 percent to $8.6 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL2 differs from TSL1 in that DL6 and DL7 must meet EL3, up from baseline for DL 6 and EL2 for DL 7, which will likely require advanced core construction techniques, including mitering or wound core designs. Much of the incremental investment needed at TSL2 is due to the increase from EL2 to EL3 in DL7, which represents more than three-quarters of the market by core weight in this superclass. This increase in stringency for DL7 drives the need for investment in mitering capacity. All major manufacturers already have mitering capability but moving the high-volume DL7 from butt-lap to mitered cores would slow throughput and require additional capacity. A range of options are still available at TSL2 as manufacturers could use higher grade steels, mitering, or wound cores. Additionally, at TSL2, manufacturers will still be able to use M6, which is common in the current market. Some manufacturers, however, usually small manufacturers, indicated during interviews they would begin to source a greater share of their cores rather than make investments in mitering machines or wound core production lines.

At TSL 3, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$26.7 million to $20.1 million, corresponding to a change in INPV of −12.2 percent to 9.1 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 53.9 percent to $6.4 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL3 represents EL4 for DL6, DL7, and DL8. DOE's engineering analysis shows that manufacturers will be able to meet EL4 using M4 or better steels. M4, however, is a thinner steel than is currently employed, which, in combination with larger cores, will dramatically slow production throughput, requiring the industry to expand capacity to maintain current shipments. This is the reason for the increase in conversion costs. In the lower-bound profitability scenario, when DOE assumes the industry cannot fully pass on incremental costs, these investments and the higher working capital needs drain cash flow and lead to the negative impacts shown in the preservation of operating profit scenario. In the high-profitability scenario, impacts are slightly positive because DOE assumes manufacturers are able to fully recoup their conversion expenditures through higher operating cash flow.

At TSL 4, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$46.1 million to $30.9 million, corresponding to a change in INPV of −21 percent to 14.1 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 102.1 percent to −$0.3 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL 4 and higher would create significant challenges for the industry and likely disrupt the marketplace. DOE's conversion costs at TSL 4 assume the industry will entirely convert to amorphous wound core technology to meet the efficiency standards. Few manufacturers of distribution transformers in this superclass have any experience with amorphous steel or wound core technology and would face a steep learning curve. This is reflected in the large conversion costs and adverse impacts on INPV in the Preservation of Operating Profit scenario. Most manufacturers DOE interviewed expected many low-volume manufacturers to exit the DOE-covered market altogether if amorphous steel was required to meet the standard. As such, DOE believes TSL 4 could lead to greater consolidation than the industry would experience at lower TSLs.

At TSL 5, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$55.3 million to $43.9 million, corresponding to a change in INPV of −25.2 percent to 20 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 122.6 percent to −$3.1 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

The impacts at TSL 5 are similar to those DOE expects at TSL 4, except that slightly more amorphous core production capacity will be needed because TSL 5-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 5 compared to TSL 4.

At TSL 6, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$83.1 million to $101.9 million, corresponding to a change in INPV of −37.9 percent to 46.4 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 125.7 percent to −$3.5 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

The impacts at TSL 6 are similar to those DOE expects at TSL 5, except that slightly more amorphous core production capacity will be needed because TSL 6-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 6 compared to TSL 5.

TABLE V.26—MANUFACTURER IMPACT ANALYSIS MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT MARKUP SCENARIO

	Units	Base case	Trial standard level				
			1	2	3	4	5
INPV	2011$M	91.0	87.1	84.5	79.7	77.1	71.0
Change in INPV	2011$ M	....	(3.8)	(6.5)	(11.3)	(13.9)	(20.0)
	%	....	(4.2)	(7.1)	(12.4)	(15.3)	(21.9)
Capital Conversion Costs	2011$M	....	2.6	4.0	7.5	10.9	11.1
Product Conversion Costs	2011$M	....	1.0	3.0	4.7	4.7	8.0
Total Conversion Costs	2011$M	....	3.6	7.0	12.2	15.6	19.1

Note: Parentheses indicate negative values.

TABLE V.27—MANUFACTURER IMPACT ANALYSIS MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE MARKUP SCENARIO

	Units	Base case	Trial standard level				
			1	2	3	4	5
INPV	2011$M	91.0	89.1	90.0	95.1	92.5	114.1
Change in INPV	2011$M	....	(1.9)	(0.9)	4.1	1.5	23.1
	%	....	(2.0)	(1.0)	4.5	1.7	25.4
Capital Conversion Costs	2011$M	....	2.6	4.0	7.5	10.9	11.1
Product Conversion Costs	2011$M	....	1.0	3.0	4.7	4.7	8.0
Total Conversion Costs	2011$M	....	3.6	7.0	12.2	15.6	19.1

Note: Parentheses indicate negative values.

At TSL 1, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$3.8 million to −$1.9 million, corresponding to a change in INPV of −4.2 percent to −2.0 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 28.1 percent to $4.1 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 1 represents EL1 for all MVDT DLs. At TSL 1, manufacturers have a variety of steels available to them, including M4, the most common steel in the superclass, in DL12, the largest DL by core steel usage. Additionally, the vast majority of the market already uses step-lap mitering technology. Therefore, DOE anticipates only moderate conversion costs for the industry, mainly associated with slower throughput due to larger cores. Some manufacturers may need to slightly expand capacity to maintain throughput and/or modify equipment to manufacturer with greater precision and tighter tolerances. In general, however, conversion expenditures should be relatively minor compared INPV. For this reason, TSL 1 yields relatively minor adverse changes to INPV in the standards case.

At TSL 2, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$6.5 million to −$0.9 million, corresponding to a change in INPV of −7.1 percent to −1.0 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 52.1 percent to $2.7 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

Compared to TSL 1, TSL 2 requires EL2, rather than EL1, in DLs 10, 12, and

13B. Because M4 (as well as the commonly used H1) can still be employed to meet these levels, DOE expects similar results at TSL 2 as at TSL 1. Slightly greater conversion costs will be required as the compliant transformers will have heavier cores, all other things being equal, meaning additionally capacity may be necessary depending on each manufacturer's current capacity utilization rate. As with TSL 1, TSL 2 will not require significant changes to most manufacturers production processes because the thickness of the steels will not change significantly, if at all.

At TSL 3, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$11.3 million to $4.1 million, corresponding to a change in INPV of −12.4 percent to 4.5 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 90.1 to $0.6 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

At TSL 4, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$13.9 million to $1.5 million, corresponding to a change in INPV of −15.3 percent to 1.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately −117.2 percent to −$1.0 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 3 and TSL 4 require EL2 for DL9 and DL10, but EL4 for DL11 through DL13B, which hold the majority of the volume. Several manufacturers were concerned TSL 3 would require some of the high volume design lines to use either H1, HO, or transition entirely to amorphous wound cores. Without a cost effective M-grade steel option, the industry could face severe disruption. Even assuming a sufficient supply of Hi-B steel, a major concern of some manufacturers because it is used and generally priced for power transformer markets, relatively large expenditures would be required in R&D and engineering as most manufacturers would have to move production to steel, with which they have little experience. DOE estimates total conversion costs would more than double at TSL 3, relative to TSL 2. If, based on the movement of steel prices, EL4 can be met cost competitively only through the use of amorphous steel or an exotic design with little or no current place in scale manufacturing, manufacturers would face significant challenges that DOE believes would lead to consolidation and likely cause many low-volume manufacturers to exit the product line or source their cores.

At TSL 5, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$20 million to $23.1 million, corresponding to a change in INPV of −21.9 percent to 25.4 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 152.8 percent to −$3.0 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 5 represents max-tech and yields results similar to but more severe than TSL 4 results. The entire market must convert to amorphous wound cores at TSL 5. Because the industry has no experience with wound core technology, and little, if any, experience with amorphous steel, this transition would represent a tremendous challenge for industry. Interviews suggest most manufacturers would exit the market altogether or source their cores rather than make the investments in plant and equipment and R&D required to meet these levels.

b. Impacts on Employment

Liquid Immersed. Based on interviews and industry research, DOE estimates that there are roughly 5,000 employees associated with DOE-covered liquid immersed distribution transformer production and some three-quarters of these workers are located domestically. DOE does not expect large changes in domestic employment to occur due to today's proposed standard. Manufacturers generally agreed that amorphous production is more labor-intensive and would require greater labor expenditures than traditional steel core production. So long as domestic plants are not relocated outside the country, DOE expects moderate increases in domestic employment at TSL1 and TSL2. There could be a small drop in employment at small, domestic manufacturing firms if small manufacturers began sourcing cores. This employment would presumably transfer to the core makers, some of whom are domestic and some of whom are foreign. There is a risk that energy conservation standards that largely require the use of amorphous steel could cause even large manufacturers who are currently producing transformers in the U.S. to evaluate offshore options. Faced with the prospect of wholesale changes to their production process, large investments and stranded assets, some manufacturers expect to strongly consider shifting production offshore at TSL 3, due to the increased labor expenses associated with the production processes required to make amorphous steel cores. In summary, at TSLs 1 and 2, DOE does not expect significant impacts on employment, but at TSL 3 or greater, which would require more investment, the impact is very uncertain.

Low-Voltage Dry-Type. Based on interviews with manufacturers, DOE estimates that there are approximately 2,200 employees associated with DOE-covered LVDT production. Approximately 75 percent of these employees are located outside of the U.S. Typically, high volume units are made in Mexico, taking advantage of lower labor rates, while custom designs are made closer to the manufacturer's customer base or R&D centers. DOE does not expect large changes in domestic employment to occur due to a standard. Most production already occurs outside the U.S., and, by and large, manufacturers agreed that most design changes necessary to meet higher energy conservation standards would increase labor expenditures, not decrease it. If, however, small manufacturers began sourcing cores instead of manufacturing them in-house, there could be a small drop in employment at these firms. This employment would presumably transfer to the core makers, some of whom are domestic and some of whom are foreign. In summary, DOE does not expect significant changes to domestic LVDT industry employment levels as a result of the proposed standards. Higher TSLs may lead to small declines in domestic employment as more firms will be challenged with what amounts to clean-sheet redesigns. Facing the prospect of greenfield investments, these manufacturers may elect to make those investments in lower-labor cost countries.

Medium-Voltage Dry-Type. Based on interviews with manufacturers, DOE estimates that there are approximately 1,850 employees associated with DOE-covered MVDT production. Approximately 75 percent of these employees are located domestically. With the exception of TSLs that require amorphous cores, manufacturers agreed that most design changes necessary to meet higher energy conservation standards would increase labor expenditures, not decrease them, but current production equipment would not be stranded, mitigating any incentive to move production offshore. Corroborating this, the largest manufacturer and domestic employer in this market has indicated that the standard, as proposed in this rule, will not cause their company to reconsider production location. As such, DOE does not expect significant changes to domestic MVDT industry employment levels as a result of the standard proposed in this rule. For TSLs that would require amorphous cores, DOE does anticipate significant changes to domestic MVDT industry employment levels.

c. Impacts on Manufacturing Capacity

Based on manufacturer interviews, DOE believes that there is significant excess capacity in the distribution transformer market. Shipments in the industry are well down from their peak in 2007, according to manufacturers. Therefore, DOE does not believe there would be any production capacity constraints at TSLs that do not require dramatic transitions to amorphous cores. For those TSLs that require amorphous cores in significant volumes, DOE believes there is potential for capacity constraints in the near term due to limitations on core steel availability. However, for the levels proposed in this rule, DOE does not foresee any capacity constraints.

d. Impacts on Subgroups of Manufacturers

Small manufacturers, niche equipment manufacturers, and manufacturers exhibiting a cost structure substantially different from the industry average could be affected disproportionately. As discussed in section V.B.2.a, using average cost assumptions to develop an industry cash-flow estimate is inadequate to assess differential impacts among manufacturer subgroups. DOE considered four subgroups in the MIA: Liquid-immersed, dry-type medium-voltage, dry-type low-voltage, and small manufacturers. For a discussion of the impacts on the first three groups, see section IV.I.1. For a discussion of the impacts on the small manufacturer subgroup, see the Regulatory Flexibility Analysis in section VI.B and chapter 12 of the NOPR TSD.

e. Cumulative Regulatory Burden

While any one regulation may not impose a significant burden on manufacturers, the combined effects of recent or impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory burden. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency. During previous stages of this rulemaking DOE identified a number of requirements in addition to amended energy conservation standards for distribution transformers. The following section briefly addresses comments DOE received with respect to cumulative regulatory burden and summarizes other key related concerns that manufacturers raised during interviews.

Many interested parties have expressed concerns about the recent implementation of previous standards for distribution transformers. For low-voltage dry-type distribution transformers, the Energy Policy Act of 2005 required compliance with NEMA TP–1 standards by the beginning of 2007. For liquid-immersed and medium-voltage dry-type transformers, DOE's 2007 energy conservation standards rulemaking required compliance by the beginning of 2010. Power Partners has stated that the last set of energy conservation standards for distribution transformers went into effect very recently and required large capital investments and retooling. Therefore, any new standards which would require additional retooling and investment would create a cumulative burden for manufacturers. (PP, No. 19 at p. 1) EEI also commented that DOE standards were increased less than 14 months ago, with effective dates of January 1, 2007 for low-voltage dry-type distribution transformers and January 1, 2010 for medium-voltage dry-type and liquid-immersed designs. (EEI, Pub. Mtg. Tr., No. 34 at p. 28)

Other factors that manufacturers stated may contribute to cumulative regulatory burden are foreign regulations and Underwriters Laboratories listing compliance requirements. Manufacturers that export their products to places such as Canada, China, Mexico, or the Middle East need to comply with foreign as well as domestic regulations. The Canadian government regulates efficiency of dry-type transformers through its Canadian Standards Association (CSA) standard C802.2–00 (effective January 1, 2005). China regulates transformer efficiency through its China Compulsory Certification (CCC) program (effective May 1, 2002), which requires manufacturers of various products including transformers to obtain the CCC Mark before exporting to or selling in the Chinese market. In Mexico, liquid-immersed units are regulated through NOM–002–SEDE–2010.

DOE discusses these and other requirements, and includes the full details of the cumulative regulatory burden analysis, in Chapter 12 of the NOPR TSD.

3. National Impact Analysis

a. Significance of Energy Savings

To estimate the energy savings through 2045 attributable to potential standards for distribution transformers, DOE compared the energy consumption of those products under the base case to their energy consumption under each TSL. Table V.28 presents the forecasted NES for each considered TSL. The savings were calculated using the approach described in section IV.G.

TABLE V.28—CUMULATIVE NATIONAL ENERGY SAVINGS FOR DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS IN 2016–2045

	Trial Standard Level						
	1	2	3	4	5	6	7
Liquid-Immersed							
Cumulative Source Savings 2045 (Quads)	0.36	0.74	0.82	1.44	1.42	1.70	2.70
Low-Voltage Dry-Type							
Cumulative Source Savings 2045 (Quads)	1.09	1.12	1.29	1.86	1.90	2.08	

TABLE V.28—CUMULATIVE NATIONAL ENERGY SAVINGS FOR DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS IN 2016–2045—Continued

	Trial Standard Level						
	1	2	3	4	5	6	7
Medium-Voltage Dry-Type							
Cumulative Source Savings 2045 (Quads)	0.06	0.13	0.23	0.23	0.37		

Chapter 10 of the NOPR TSD provides additional details on the NES values reported and also presents tables that show the magnitude of the energy savings discounted at rates of 3 percent and 7 percent. Discounted energy savings represent a policy perspective in which energy savings realized farther in the future are less significant than energy savings realized in the nearer term.

b. Net Present Value of Customer Costs and Benefits

DOE estimated the cumulative NPV to the Nation of the total costs and savings for customers that would result from the TSLs considered for distribution transformers. In accordance with the OMB's guidelines on regulatory analysis,[41] DOE calculated NPV using both a 7-percent and a 3-percent real discount rate. The 7-percent rate is an estimate of the average before-tax rate of return on private capital in the U.S. economy, and reflects the returns on real estate and small business capital as well as corporate capital. DOE used this discount rate to approximate the opportunity cost of capital in the private sector, because recent OMB analysis has found the average rate of return on capital to be near this rate. DOE used the 3-percent rate to capture the potential effects of standards on private consumption (*e.g.,* through higher prices for products and reduced purchases of energy). This rate represents the rate at which society discounts future consumption flows to their present value. This rate can be approximated by the real rate of return on long-term government debt (*i.e.,* yield on United States Treasury notes minus annual rate of change in the Consumer Price Index), which has averaged about 3 percent on a pre-tax basis for the past 30 years.

Table V.29 shows the customer NPV results for each TSL DOE considered for distribution transformers, using both a 7-percent and a 3-percent discount rate. In each case, the impacts cover the lifetime of products purchased in 2016–2045. See chapter 10 of the NOPR TSD for more detailed NPV results.

TABLE V.29—CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR DISTRIBUTION TRANSFORMERS TRIAL STANDARD LEVELS FOR UNITS SOLD IN 2016–2045

	Discount rate (%)	Trial Standard Level						
		1	2	3	4	5	6	7
Liquid-Immersed								
Net Present Value (billion 2010$)	3	3.66	7.39	8.24	14.21	13.48	13.17	−1.11
	7	0.75	1.51	1.73	2.96	2.65	1.76	−8.25
Low-Voltage Dry-Type								
Net Present Value (billion 2010$)	3	7.81	7.79	8.51	11.16	9.37	2.69	
	7	2.03	1.97	2.03	2.36	1.37	−2.41	
Medium-Voltage Dry-Type								
Net Present Value (billion 2010$)	3	0.42	0.67	0.90	0.90	−0.38		
	7	0.10	0.13	0.06	0.06	−0.84		

The results shown here reflect the default product price trend, which uses constant prices. DOE conducted an NPV sensitivity analysis using alternative price trends. DOE developed one forecast in which prices decline after 2010, and one in which prices rise. The NPV results from the associated sensitivity cases are described in appendix 10–C of the NOPR TSD.

c. Indirect Impacts on Employment

As discussed above, DOE expects energy conservation standards for distribution transformers to reduce energy costs for equipment owners, and

[41] OMB Circular A–4, section E (Sept. 17, 2003). Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4.* (Last accessed March 18, 2011.)

the resulting net savings to be redirected to other forms of economic activity. Those shifts in spending and economic activity could affect the demand for labor. As described in section IV.J, DOE used an input/output model of the U.S. economy to estimate indirect employment impacts of the TSLs that DOE considered in this rulemaking. DOE understands that there are uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Therefore, DOE generated results for near-term timeframes (2015–2020), where these uncertainties are reduced.

The results suggest that today's proposed standards are likely to have negligible impact on the net demand for labor in the economy. The net change in jobs is so small that it would be imperceptible in national labor statistics and might be offset by other, unanticipated effects on employment. Chapter 13 of the NOPR TSD presents more detailed results.

4. Impact on Utility or Performance of Equipment

DOE believes that the standards it is proposing today will not lessen the utility or performance of distribution transformers.

5. Impact of Any Lessening of Competition

DOE has also considered any lessening of competition that is likely to result from new and amended standards. The Attorney General determines the impact, if any, of any lessening of competition likely to result from a proposed standard, and transmits such determination to the Secretary, together with an analysis of the nature and extent of such impact. (42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii))

To assist the Attorney General in making such a determination, DOE has provided DOJ with copies of this notice and the TSD for review. DOE will consider DOJ's comments on the proposed rule in preparing the final rule, and DOE will publish and respond to DOJ's comments in that document.

6. Need of the Nation to Conserve Energy

Enhanced energy efficiency, where economically justified, improves the Nation's energy security, strengthens the economy, and reduces the environmental impacts or costs of energy production. Reduced electricity demand due to energy conservation standards is also likely to reduce the cost of maintaining the reliability of the electricity system, particularly during peak-load periods. As a measure of the expected energy conservation out to 2045, Table V.30 presents the estimated energy savings in terms of equivalent generating capacity for the TSLs that DOE considered in this rulemaking.

TABLE V.30—EXPECTED ENERGY SAVINGS OUT TO 2045 REPRESENTED AS EQUIVALENT GENERATING CAPACITY UNDER DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS

	Trial standard level						
	1	2	3	4	5	6	7
Liquid-Immersed (GW)	0.610	1.23	1.33	2.24	2.21	2.53	3.73
Low-Voltage Dry-Type (GW)	1.62	1.66	1.90	2.70	2.75	2.92	—
Medium-Voltage Dry-Type (GW)	0.091	0.174	0.332	0.332	0.510	—	—
Total	2.33	3.06	3.56	5.28	5.47	5.46	3.73

Energy savings from standards for distribution transformers could also produce environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases associated with electricity production. Table V.31 provides DOE's estimate of cumulative CO_2, NO_X, and Hg emissions reductions projected to result from the TSLs considered in this rulemaking. DOE reports annual CO_2, NO_X, and Hg emissions reductions for each TSL in chapter 15 of the NOPR TSD.

As discussed in section IV.M, DOE did not report SO_2 emissions reductions from power plants because, due to SO_2 emissions caps, there is uncertainty about the effect of energy conservation standards on the overall level of SO_2 emissions in the United States. DOE also did not include NO_X emissions reduction from power plants in States subject to CAIR because an energy conservation standard would not affect the overall level of NO_X emissions in those States due to the emissions caps mandated by CAIR.

TABLE V.31—SUMMARY OF EMISSIONS REDUCTION ESTIMATED FOR DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS (CUMULATIVE IN 2016–2045)

	Trial standard level						
	1	2	3	4	5	6	7
Liquid-Immersed							
CO_2 (million metric tons)	31.2	62.7	67.7	113	112	128	186
NO_X (thousand tons)	25.5	51.2	55.3	92.7	91.5	104	152
Hg (*tons*)	0.209	0.420	0.454	0.762	0.751	0.857	1.25
Low-Voltage Dry-Type							
CO_2 (million metric tons)	82.1	83.9	96.0	137	139	148	—
NO_X (thousand tons)	67.0	68.6	78.4	112	114	121	—
Hg (*tons*)	0.551	0.564	0.645	0.918	0.934	0.992	—
Medium-Voltage Dry-Type							
CO_2 (million metric tons)	4.62	8.80	16.8	16.8	25.7	—	—
NO_X (thousand tons)	3.77	7.19	13.7	13.7	21.0	—	—

TABLE V.31—SUMMARY OF EMISSIONS REDUCTION ESTIMATED FOR DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS (CUMULATIVE IN 2016–2045)—Continued

	Trial standard level						
	1	2	3	4	5	6	7
Hg (*tons*)	0.031	0.059	0.113	0.113	0.173	—	—

As part of the analysis for this proposed rule, DOE estimated monetary benefits likely to result from the reduced emissions of CO_2 and NO_X that DOE estimated for each of the TSLs considered. As discussed in section IV.M, DOE used values for the SCC developed by an interagency process. The four values for CO_2 emissions reductions resulting from that process (expressed in 2010$) are $4.9/metric ton (the average value from a distribution that uses a 5-percent discount rate), $22.3/metric ton (the average value from a distribution that uses a 3-percent discount rate), $36.5/metric ton (the average value from a distribution that uses a 2.5-percent discount rate), and $67.6/metric ton (the 95th-percentile value from a distribution that uses a 3-percent discount rate). These values correspond to the value of emission reductions in 2010; the values for later years are higher due to increasing damages as the magnitude of climate change increases.

Table V.32 presents the global value of CO_2 emissions reductions at each TSL. For each of the four cases, DOE calculated a present value of the stream of annual values using the same discount rate as was used in the studies upon which the dollar-per-ton values are based. DOE calculated domestic values as a range from 7 percent to 23 percent of the global values, and these results are presented in chapter 16 of the NOPR TSD.

TABLE V.32—ESTIMATES OF GLOBAL PRESENT VALUE OF CO_2 EMISSIONS REDUCTION UNDER DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS

[Million 2010$]

TSL	5% discount rate, average *	3% discount rate, average *	2.5% discount rate, average *	3% discount rate, 95th percentile *
Liquid-Immersed				
1	173	1003	1747	3051
2	350	2026	3528	6160
3	382	2219	3866	6746
4	655	3831	6681	11643
5	646	3779	6591	11486
6	752	4414	7705	13414
7	1140	6754	11811	20523
Low-Voltage Dry-Type				
1	481	2820	4921	8570
2	492	2884	5032	8764
3	562	3297	5753	10020
4	800	4693	8190	14264
5	814	4776	8336	14517
6	866	5076	8858	15427
Medium-Voltage Dry-Type				
1	27	159	277	483
2	52	302	528	919
3	98	576	1006	1751
4	98	576	1006	1751
5	151	884	1543	2688

DOE is well aware that scientific and economic knowledge about the contribution of CO_2 and other GHG emissions to changes in the future global climate and the potential resulting damages to the world economy continues to evolve rapidly. Thus, any value placed on reducing CO_2 emissions in this rulemaking is subject to change. DOE, together with other Federal agencies, will continue to review various methodologies for estimating the monetary value of reductions in CO_2 and other GHG emissions. This ongoing review will consider the comments on this subject that are part of the public record for this and other rulemakings, as well as other methodological assumptions and issues. However, consistent with DOE's legal obligations, and taking into account the uncertainty involved with this particular issue, DOE has included in this NOPR the most recent values and analyses resulting from the ongoing interagency review process.

DOE also estimated a range for the cumulative monetary value of the economic benefits associated with NO_X emissions reductions anticipated to result from amended standards for refrigeration products. The low and high dollar-per-ton values that DOE used are discussed in section IV.M. Table V.33 presents the cumulative present values for each TSL calculated using 7-percent and 3-percent discount rates.

TABLE V.33—ESTIMATES OF PRESENT VALUE OF NO_X EMISSIONS REDUCTION UNDER DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS

	Million 2010$	
TSL	3% discount rate	7% discount rate
Liquid-Immersed		
1	9 to 94	3 to 32
2	19 to 191	6 to 64
3	20 to 208	7 to 69
4	35 to 356	11 to 117
5	34 to 351	11 to 115
6	40 to 408	13 to 132
7	60 to 616	19 to 194
Low-Voltage Dry-Type		
1	25 to 261	8 to 85
2	26 to 267	8 to 87
3	30 to 305	10 to 99
4	42 to 434	14 to 141
5	43 to 442	14 to 143
6	46 to 470	15 to 152
Medium-Voltage Dry-Type		
1	1 to 15	0 to 5
2	3 to 28	1 to 9
3	5 to 53	2 to 17
4	5 to 53	2 to 17
5	8 to 82	3 to 27

7. Summary of National Economic Impacts

The NPV of the monetized benefits associated with emissions reductions can be viewed as a complement to the NPV of the customer savings calculated for each TSL considered in this rulemaking. Table V.34 through Table V.36 present the NPV values that result from adding the estimates of the potential economic benefits resulting from reduced CO_2 and NO_X emissions in each of four valuation scenarios to the NPV of customer savings calculated for each TSL considered in this rulemaking, at both a seven-percent and three-percent discount rate. The CO_2 values used in the columns of each table correspond to the four scenarios for the valuation of CO_2 emission reductions presented in section IV.M.

TABLE V.34—LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: NET PRESENT VALUE OF CUSTOMER SAVINGS COMBINED WITH NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS

[Billion 2010$]

TSL	Consumer NPV at 3% discount rate added with:			
	SCC Value of $4.9/metric ton CO_2* and Low Value for NO_X**	SCC Value of $22.3/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $36.5/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $67.6/metric ton CO_2* and High Value for NO_X**
1	3.8	4.7	5.5	6.8
2	7.8	9.5	11.0	13.7
3	8.6	10.6	12.2	15.2
4	14.9	18.2	21.1	26.2
5	14.2	17.5	20.3	25.3
6	14.0	17.8	21.1	27.0
7	0.1	6.0	11.0	20.0
TSL	Consumer NPV at 7% Discount Rate added with:			
	SCC Value of $4.9/metric ton CO_2* and Low Value for NO_X**	SCC Value of $22.3/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $36.5/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $67.6/metric ton CO_2* and High Value for NO_X**
1	0.9	1.8	2.5	3.8
2	1.9	3.6	5.1	7.7
3	2.1	4.0	5.6	8.5
4	3.6	6.9	9.7	14.7
5	3.3	6.5	9.3	14.3
6	2.5	6.2	9.5	15.3
7	−7.1	−1.4	3.7	12.5

* These label values represent the global SCC in 2010, in 2010$. The present values have been calculated with scenario-consistent discount rates.

** Low Value corresponds to $450 per ton of NO_X emissions. Medium Value corresponds to $2,537 per ton of NO_X emissions. High Value corresponds to $4,623 per ton of NO_X emissions.

TABLE V.35—LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: NET PRESENT VALUE OF CUSTOMER SAVINGS COMBINED WITH NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS

[Billion 2010$]

TSL	Consumer NPV at 3% Discount Rate added with:			
	SCC Value of $4.9/metric ton CO_2* and Low Value for NO_X**	SCC Value of $22.3/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $36.5/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $67.6/metric ton CO_2* and High Value for NO_X**
1	8.3	10.8	12.9	16.6
2	8.3	10.8	13.0	16.8
3	9.1	12.0	14.4	18.8
4	12.0	16.1	19.6	25.9
5	10.2	14.4	17.9	24.3
6	3.6	8.0	11.8	18.6
TSL	Consumer NPV at 7% Discount Rate added with:			
	SCC Value of $4.9/metric ton CO_2* and Low Value for NO_X**	SCC Value of $22.3/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $36.5/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $67.6/metric ton CO_2* and High Value for NO_X**
1	2.5	4.9	7.0	10.7
2	2.5	4.9	7.1	10.8
3	2.6	5.4	7.8	12.1
4	3.2	7.1	10.6	16.8
5	2.2	6.2	9.8	16.0
6	−1.5	2.7	6.5	13.2

TABLE V.36—MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: NET PRESENT VALUE OF CUSTOMER SAVINGS COMBINED WITH NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS

[Billion 2010$]

TSL	Consumer NPV at 3% Discount Rate added with:			
	SCC Value of $4.9/metric ton CO_2* and Low Value for NO_X**	SCC Value of $22.3/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $36.5/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $67.6/metric ton CO_2* and High Value for NO_X**
1	0.5	0.6	0.7	0.9
2	0.7	1.0	1.2	1.6
3	1.0	1.5	1.9	2.7
4	1.0	1.5	1.9	2.7
5	−0.2	0.6	1.2	2.4
TSL	Consumer NPV at 7% Discount Rate added with:			
	SCC Value of $4.9/metric ton CO_2* and Low Value for NO_X**	SCC Value of $22.3/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $36.5/metric ton CO_2* and Medium Value for NO_X**	SCC Value of $67.6/metric ton CO_2* and High Value for NO_X**
1	0.1	0.3	0.4	0.6
2	0.2	0.4	0.7	1.1
3	0.2	0.6	1.1	1.8
4	0.2	0.6	1.1	1.8
5	−0.7	0.1	0.7	1.9

Although adding the value of customer savings to the values of emission reductions provides a valuable perspective, two issues should be considered. First, the national operating cost savings are domestic U.S. customer monetary savings that occur as a result of market transactions, while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and the SCC are performed with different methods that use quite different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2016–2045. The SCC values, on the other hand, reflect the present value of future climate-related impacts resulting from the emission of one metric ton of CO_2 in each year. These impacts continue well beyond 2100.

8. Other Factors

The Secretary of Energy, in determining whether a standard is economically justified, may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VI))

Electrical steel is a critical consideration in the design and manufacture of distribution transformers, amounting for more than 60 percent of the distribution transformers mass in some designs. Rapid changes in the supply or pricing of certain grades can seriously hinder manufacturers' abilities to meet the market demand and, as a result, this rulemaking has given an uncommon level of attention to effects of electrical steel supply and availability.

The most important point to note is that several energy efficiency levels in each design line are reachable only by using amorphous steel, which is available in the United States from a single supplier that does not have enough present capacity to supply the industry at all-amorphous standard levels. Several more energy efficiency levels are reachable with the top grades of conventional electrical steels (''grain-oriented'') but result in distribution transformers that are unlikely to be cost-competitive with the often more-efficient amorphous units. As stated above, switching to amorphous steel is not practicable as there are availability concerns with amorphous steel.

Distribution transformers are also highly customized products; manufacturers routinely build only one or a handful of units of a particular design and require flexibility with respect to construction materials in order to do this competitively. Setting a standard that either technologically or economically required amorphous material would both eliminate a large amount of design flexibility and expose the industry to enormous risk with respect to supply and pricing of core steel. For both reasons, DOE considered electrical steel availability to be a major factor in determining which TSLs were economically justified.

C. Proposed Standards

When considering proposed standards, the new or amended energy conservation standard that DOE adopts for any type (or class) of covered product shall be designed to achieve the maximum improvement in energy efficiency that the Secretary determines is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) In determining whether a standard is economically justified, the Secretary must determine whether the benefits of the standard exceed its burdens to the greatest extent practicable, in light of the seven statutory factors discussed previously. (42 U.S.C. 6295(o)(2)(B)(i)) The new or amended standard must also ''result in significant conservation of energy.'' (42 U.S.C. 6295(o)(3)(B))

For today's NOPR, DOE considered the impacts of standards at each TSL, beginning with the maximum technologically feasible level, to determine whether that level was economically justified. Where the max-tech level was not justified, DOE then considered the next most efficient level and undertook the same evaluation until it reached the highest efficiency level that is both technologically feasible and economically justified and saves a significant amount of energy.

To aid the reader in understanding the benefits and/or burdens of each TSL, tables in this section summarize the quantitative analytical results for each TSL, based on the assumptions and methodology discussed herein. The efficiency levels contained in each TSL are described in section V.A. In addition to the quantitative results presented in the tables, DOE also considers other burdens and benefits that affect economic justification. These include the impacts on identifiable subgroups of customers who may be disproportionately affected by a national standard, and impacts on employment. Section V.B.1 presents the estimated impacts of each TSL for these subgroups. DOE discusses the impacts on employment in transformer manufacturing in section V.B.2.b, and discusses the indirect employment impacts in section V.B.3.c.

1. Benefits and Burdens of Trial Standard Levels Considered for Liquid-Immersed Distribution Transformers

Table V.37 and Table V.38 summarize the quantitative impacts estimated for each TSL for liquid-immersed distribution transformers.

TABLE V.37—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
National Energy Savings (*quads*).	0.36	0.74	0.82	1.44	1.42	1.70	2.70
NPV of Consumer Benefits (2010$ billion)							
3% discount rate	3.66	7.39	8.24	14.21	13.48	13.17	−1.11
7% discount rate	0.75	1.51	1.73	2.96	2.65	1.76	−8.25
Cumulative Emissions Reduction							
CO_2 (million metric tons).	31.2	62.7	67.7	113	112	128	186
NO_X (thousand tons).	25.5	51.2	55.3	92.7	91.5	104	152
Hg (*tons*)	0.209	0.420	0.454	0.762	0.751	0.857	1.25
Value of Emissions Reduction							
CO_2 (2010$ million)*.	173 to 3051	350 to 6,160	382 to 6,746	655 to 11,643	646 to 11,486	752 to 13,414	1140 to 20,523
NO_X—3% discount rate (*2010$ million*).	9 to 94	19 to 191	20 to 208	35 to 356	34 to 351	40 to 408	60 to 616

TABLE V.37—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: NATIONAL IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
NO_X—7% discount rate (*2010$ million*).	3 to 32	6 to 64	7 to 69	11 to 117	11 to 115	13 to 132	19 to 194

* Range of the economic value of CO_2 reductions is based on estimates of the global benefit of reduced CO_2 emissions.

TABLE V.38—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Manufacturer Impacts							
Industry NPV (2011$ million).	586 to 615	532 to 583	524 to 578	461 to 552	451 to 537	428 to 548	298 to 673
Industry NPV (% change).	(6.3) to (1.7)	(14.9) to (6.7)	(16.2) to (7.6)	(26.2) to (11.8)	(27.8) to (14.1)	(31.6) to (12.4)	(52.3) to 7.7
Consumer Mean LCC Savings (2010$)							
Design line 1	36	36	36	641	641	532	50
Design line 2	0	309	309	338	300	250	−736
Design line 3	2413	2413	3831	5591	5245	6531	4135
Design line 4	862	862	862	3356	3356	3362	1274
Design line 5	7787	7787	10288	12513	11395	12746	3626
Consumer Median PBP (years)							
Design line 1	20.2	20.2	20.2	7.9	7.9	10.0	19.2
Design line 2	0.0	6.9	6.9	8.0	9.5	11.5	24.3
Design line 3	6.3	6.3	4.0	4.7	4.6	5.2	13.3
Design line 4	5.0	5.0	5.0	4.1	4.1	4.1	14.6
Design line 5	4.0	4.0	4.2	6.3	5.7	8.3	16.9
Distribution of Consumer LCC Impacts							
Design line 1							
Net Cost (%).	57.9	57.9	57.9	4.8	4.8	8.0	55.4
Net Benefit (%).	41.8	41.8	41.8	95.0	95.0	92.0	44.6
No Impact (%).	0.2	0.2	0.2	0.2	0.2	0.0	0.0
Design line 2							
Net Cost (%).	0.0	14.2	14.2	9.8	11.2	15.8	80.2
Net Benefit (%).	0.0	85.8	85.8	90.2	88.8	84.3	19.8
No Impact (%).	100.0	0.0	0.0	0.0	0.0	0.0	0.0
Design line 3							
Net Cost (%).	15.7	15.7	11.2	4.0	5.3	3.9	25.1
Net Benefit (%).	83.0	83.0	87.7	96.0	94.6	96.1	74.9
No Impact (%).	1.4	1.4	1.2	0.0	0.0	0.0	0.0
Design line 4							
Net Cost (%).	6.0	6.0	6.0	1.9	1.9	1.9	31.1
Net Benefit (%).	93.5	93.5	93.5	97.5	97.5	97.6	63.9
No Impact (%).	0.6	0.6	0.6	0.6	0.6	0.6	0.0
Design line 5							
Net Cost (%).	19.1	19.1	13.2	7.8	10.4	7.9	39.9

TABLE V.38—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Net Benefit (%).	80.6	80.6	86.8	92.2	89.6	92.1	60.1
No Impact (%).	0.4	0.4	0.1	0.0	0.0	0.0	0.0

First, DOE considered TSL 7, the most efficient level (max tech), which would save an estimated total of 2.70 quads of energy through 2045, an amount DOE considers significant. TSL 7 has an estimated NPV of customer benefit of −$8.25 billion using a 7 percent discount rate, and −$1.11 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 7 are 186 million metric tons of CO_2, 152 thousand tons of NO_X, and 1.25 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 7 ranges from $1,140 million to $20,523 million.

At TSL 7, the average LCC impact ranges from −$736 for design line 2 to $4,135 for design line 3. The median PBP ranges from 24.3 years for design line 2 to 13.3 years for design line 3. The share of customers experiencing a net LCC benefit ranges from 19.8 percent for design line 2 to 74.9 percent for design line 3.

At TSL 7, the projected change in INPV ranges from a decrease of $327 million to an increase of $48 million. If the decrease of $327 million were to occur, TSL 7 could result in a net loss of 52.3 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 7, there is a risk of very large negative impacts on manufacturers due to the substantial capital and engineering costs they would incur and the market disruption associated with the likely transition to a market entirely served by amorphous steel. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing transformers at the price points projected for TSL 7 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous transformer production capacity. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing transformers at the price points projected for TSL 7 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous transformer production capacity. DOE also has concerns about the competitive impact of TSL 7 on the electrical steel industry, as only one proven supplier of amorphous ribbon currently serves the U.S. market.

The Secretary tentatively concludes that, at TSL 7 for liquid-immersed distribution transformers, the benefits of energy savings, positive average customer LCC savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the potential multi-billion dollar negative net economic cost, the economic burden on customers as indicated by large PBPs, significant increases in installed cost, and the large percentage of customers who would experience LCC increases, the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 7. Consequently, DOE has tentatively concluded that TSL 7 is not economically justified.

Next, DOE considered TSL 6, which would save an estimated total of 1.70 quads of energy through 2045, an amount DOE considers significant. TSL 6 has an estimated NPV of customer benefit of $1.76 billion using a 7 percent discount rate, and $13.17 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 6 are 128 million metric tons of CO_2, 104 thousand tons of NO_X, and 0.857 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 6 ranges from $752 million to $13,414 million.

At TSL 6, the average LCC impact ranges from $250 for design line 2 to $12,746 for design line 5. The median PBP ranges from 11.5 years for design line 2 to 4.1 years for design line 4. The share of customers experiencing a net LCC benefit ranges from 84.3 percent for design line 2 to 97.6 percent for design line 4.

At TSL 6, the projected change in INPV ranges from a decrease of $198 million to a decrease of $78 million. If the decrease of $198 million were to occur, TSL 6 could result in a net loss of 31.6 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 6, DOE recognizes the risk of very large negative impacts on manufacturers due to the large capital and engineering costs and the market disruption associated with the likely transition to a market entirely served by amorphous steel. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing their transformers at the price points projected for TSL 6 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous transformer production capacity.

The energy savings under TSL 6 are achievable only by using amorphous steel, which is currently available from a single supplier that has annual production capacity of approximately 100,000 tons, the vast majority of which serves global demand. Thus, current availability is far below the amount that would be required to meet the U.S. liquid-immersed transformer market demand of approximately 250,000 tons. Electrical steel is a critical consideration in the manufacture of distribution transformers, accounting for more than 60 percent of the transformer's mass in some designs. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. Therefore, setting a standard that requires amorphous material would expose the industry to enormous risk with respect to core steel supply. DOE also has concerns about the competitive impact of TSL 6 on the electrical steel industry. TSL 6 could jeopardize the ability of silicon steels to compete with amorphous metal, which risks upsetting competitive balance among steel suppliers and between them and their customers.

The Secretary tentatively concludes that, at TSL 6 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 6. Consequently, DOE has tentatively concluded that TSL 6 is not economically justified.

Next, DOE considered TSL 5, which would save an estimated total of 1.42 quads of energy through 2045, an amount DOE considers significant. TSL 5 has an estimated NPV of customer benefit of $2.65 billion using a 7 percent discount rate, and $13.48 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 5 are 112 million metric tons of CO_2, 104 thousand tons of NO_X, and 0.751 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $646 million to $11,486 million.

At TSL 5, the average LCC impact ranges from $300 for design line 2 to $11,395 for design line 5. The median PBP ranges from 9.5 years for design line 2 to 4.1 years for design line 4. The share of customers experiencing a net LCC benefit ranges from 88.8 percent for design line 2 to 97.5 percent for design line 4.

At TSL 5, the projected change in INPV ranges from a decrease of $174 million to a decrease of $88 million. If the decrease of $174 million were to occur, TSL 5 could result in a net loss of 27.8 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 5, DOE recognizes the risk of very large negative impacts on manufacturers due to the large capital and engineering costs they would incur and the market disruption associated with the likely transition to a market almost entirely served by amorphous steel. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing transformers at the price points projected for TSL 5 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous transformer production capacity.

The energy savings under TSL 5 are achievable only by using amorphous steel, which is currently available from a single supplier that has annual production capacity of 100,000 tons, far below the amount that would be required to meet the U.S. liquid-immersed transformer market demand of approximately 250,000 tons. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. Therefore, setting a standard that requires amorphous material would expose the industry to enormous risk with respect to core steel supply. As with higher TSLs, DOE also has concerns about the competitive impact of TSL 5 on the electrical steel manufacturing industry. TSL 5 could jeopardize the ability of silicon steels to compete with amorphous metal, which risks upsetting competitive balance among steel suppliers and between them and their customers.

The Secretary tentatively concludes that, at TSL 5 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 5. Consequently, DOE has concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated total of 1.44 quads of energy through 2045, an amount DOE considers significant. TSL 4 has an estimated NPV of customer benefit of $2.96 billion using a 7 percent discount rate, and $14.21 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 4 are 113 million metric tons of CO_2, 92.7 thousand tons of NO_X, and 0.762 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $655 million to $11,643 million.

At TSL 4, the average LCC impact ranges from $338 for design line 2 to $12,513 for design line 5. The median PBP ranges from 8.0 years for design line 2 to 4.1 years for design line 4. The share of customers experiencing a net LCC benefit ranges from 90.2 percent for design line 2 to 97.5 percent for design line 4.

At TSL 4, the projected change in INPV ranges from a decrease of $164 million to a decrease of $74 million. If the decrease of $164 million were to occur, TSL 4 could result in a net loss of 26.2 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 4, DOE recognizes the risk of large negative impacts on manufacturers due to the substantial capital and engineering costs they would incur. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing transformers at the price points projected for TSL 4 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous transformer production capacity.

DOE is also concerned that TSL 4, like the higher TSLs, will require amorphous steel to be competitive in many applications and at least a few design lines. As stated previously, the available supply of amorphous steel is well below the amount that would likely be required to meet the U.S. liquid-immersed transformer market demand. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. Therefore, setting a standard that requires amorphous material would expose the industry to enormous risk with respect to core steel supply.

In addition, depending on how steel prices react to a standard, DOE believes TSL 4 could threaten the viability of a place in the market for conventional steel. Therefore, as with higher TSLs, DOE has concerns about the competitive impact of TSL 4 on the electrical steel manufacturing industry.

The Secretary tentatively concludes that, at TSL 4 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 4. Consequently, DOE has tentatively concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3, which would save an estimated total of 0.82 quads of energy through 2045, an amount DOE considers significant. TSL 3 has an estimated NPV of customer benefit of $1.73 billion using a 7 percent discount rate, and $8.24 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 3 are 67.7 million metric tons of CO_2, 55.3 thousand tons of NO_X, and 0.454 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $382 million to $6,746 million.

At TSL 3, the average LCC impact ranges from $36 for design line 1 to $10,288 for design line 5. The median PBP ranges from 20.2 years for design line 1 to 4.0 years for design line 3. The share of customers experiencing a net LCC benefit ranges from 41.8 percent for design line 1 to 93.5 percent for design line 4.

At TSL 3, the projected change in INPV ranges from a decrease of $101 million to a decrease of $48 million. If the decrease of $101 million were to occur, TSL 3 could result in a net loss of 16.2 percent in INPV to manufacturers. At TSL 3, DOE recognizes the risk of large negative impacts on manufacturers due to the large capital and engineering costs they would incur.

Although the industry can manufacture liquid-immersed transformers at TSL 3 from M3 or lower grade steels, the positive LCC and national impacts results described above are based on lowest first-cost designs, which include amorphous steel for all the design lines analyzed. As is the case with higher TSLs, DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. If manufacturers were to meet standards at TSL 3 using M3 or lower grade steels, DOE's analysis shows that the LCC impacts are negative.[42]

The Secretary tentatively concludes that, at TSL 3 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 3 in a cost-effective manner. Consequently, DOE has tentatively concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2, which would save an estimated total of 0.74 quads of energy through 2045, an amount DOE considers significant. TSL 2 has an estimated NPV of customer benefit of $1.51 billion using a 7 percent discount rate, and $7.39 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 2 are 62.7 million metric tons of CO_2, 51.2 thousand tons of NO_X, and 0.42 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 2 ranges from $350 million to $6,160 million.

At TSL 2, the average LCC impact ranges from $0 for design line 2 to $7,787 for design line 5. The median PBP ranges from 20.2 years for design line 1 to 4.0 years for design line 5. The share of customers experiencing a net LCC benefit ranges from 41.8 percent for design line 1 to 93.5 percent for design line 4.

At TSL 2, the projected change in INPV ranges from a decrease of $93 million to a decrease of $42 million. If the decrease of $93 million were to occur, TSL 2 could result in a net loss of 14.9 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 2, DOE recognizes the risk of negative impacts on manufacturers due to the significant capital and engineering costs they would incur.

Although the industry can manufacture liquid-immersed transformers at TSL 2 from M3 or lower grade steels, the positive LCC and national impacts results described above are based on lowest first-cost designs, which include amorphous steel for design line 2. This design line represents approximately 44 percent of all liquid-immersed transformer shipments by MVA. Amorphous steel is available from a single supplier whose annual production capacity is below the amount that would be required to meet the demand for design line 2 under TSL 2. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. If manufacturers were to meet standards at TSL 2 using M3 or lower grade steels, DOE's analysis shows that the LCC impacts would be negative.

The Secretary tentatively concludes that, at TSL 2 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 2 in a cost-effective manner. Consequently, DOE has tentatively concluded that TSL 2 is not economically justified.

Next, DOE considered TSL 1, which would save an estimated total of 0.36 quads of energy through 2045, an amount DOE considers significant. TSL 1 has an estimated NPV of customer benefit of $0.75 billion using a 7 percent discount rate, and $3.66 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 1 are 31.2 million metric tons of CO_2, 25.5 thousand tons of NO_X, and 0.209 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 1 ranges from $173 million to $3,051 million.

At TSL 1, the average LCC impact ranges from $0 for design line 2 to $7,787 for design line 5. The median PBP ranges from 20.2 years for design line 1 to 4.0 years for design line 5. The share of customers experiencing a net LCC benefit ranges from 41.8 percent for design line 1 to 93.5 percent for design line 4.

At TSL 1, the projected change in INPV ranges from a decrease of $40 million to a decrease of $10 million. If the decrease of $40 million were to occur, TSL 1 could result in a net loss of 6.3 percent in INPV to manufacturers of liquid-immersed distribution transformers.

The energy savings under TSL 1 are achievable without using amorphous steel. Therefore, the aforementioned risks that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards, or that manufacturers may be exposed to increased material prices due to the concentration of core material to a single supplier are not present under TSL 1.

After considering the analysis and weighing the benefits and the burdens, DOE has tentatively concluded that at TSL 1 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, emission reductions, and the estimated monetary value of the emissions reductions would outweigh the potential reduction in INPV for manufacturers. The Secretary of Energy has concluded that TSL 1 would save a significant amount of energy and is technologically feasible and economically justified. In addition, during the negotiated rulemaking, NEMA and AK Steel recommended TSL 1. For the above considerations, DOE today proposes to adopt the energy conservation standards for liquid-

[42] DOE conducted a sensitivity analysis where LCC results are presented for liquid-immersed transformers without amorphous steel; see in appendix 8–C in the NOPR TSD.

immersed distribution transformers at TSL 1. Table V.39 presents the proposed energy conservation standards for liquid-immersed distribution transformers.

TABLE V.39—PROPOSED ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Electrical efficiency by kVA and equipment class			
Equipment class 1		Equipment class 2	
kVA	Percent	kVA	Percent
10	98.70	15	98.65
15	98.82	30	98.83
25	98.95	45	98.92
37.5	99.05	75	99.03
50	99.11	112.5	99.11
75	99.19	150	99.16
100	99.25	225	99.23
167	99.33	300	99.27
250	99.39	500	99.35
333	99.43	750	99.40
500	99.49	1000	99.43
		1500	99.48

2. Benefits and Burdens of Trial Standard Levels Considered for Low-Voltage, Dry-Type Distribution Transformers

Table V.40 and Table V.41 summarize the quantitative impacts estimated for each TSL for low-voltage, dry-type distribution transformers.

TABLE V.40—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
National Energy Savings (quads)	1.09	1.12	1.29	1.86	1.90	2.08
NPV of Consumer Benefits (2010$ billion)						
3% discount rate	7.81	7.79	8.51	11.16	9.37	2.69
7% discount rate	2.03	1.97	2.03	2.36	1.37	−2.41
Cumulative Emissions Reduction						
CO_2 (million metric tons)	82.1	83.9	96.0	137	139	148
NO_X (thousand tons)	67.0	68.6	78.4	112	114	121
Hg (tons)	0.551	0.564	0.645	0.918	0.934	0.992
Value of Emissions Reduction						
CO_2 (2010$ million)*	481 to 8570	492 to 8764	562 to 10020	800 to 14264	814 to 14517	866 to 15427
NO_X—3% discount rate (2010$ million)	25 to 261	26 to 267	30 to 305	42 to 434	43 to 442	46 to 470
NO_X—7% discount rate (2010$ million)	8 to 85	8 to 87	10 to 99	14 to 141	14 to 143	15 to 152

* Range of the economic value of CO_2 reductions is based on estimates of the global benefit of reduced CO_2 emissions.

TABLE V.41—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
Manufacturer Impacts						
Industry NPV (2011$ million)	203 to 236	200 to 235	193 to 240	173 to 250	164 to 263	136 to 322
Industry NPV (% change)	(7.7) to 7.7	(8.9) to 6.8	(12.2) to 9.1	(21.0) to 14.1	(25.2) to 20.0	(37.9) to 46.4
Consumer Mean LCC Savings (2010$)						
Design line 6	0	−125	335	187	187	−881
Design line 7	1714	1714	1793	2270	2270	270

TABLE V.41—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
Design line 8	2476	2476	2625	4145	−2812	−2812
Consumer Median PBP (years)						
Design line 6	0.0	24.7	13.0	16.3	16.3	32.4
Design line 7	4.5	4.5	4.7	6.9	6.9	18.1
Design line 8	8.4	8.4	12.3	11.0	24.5	24.5
Distribution of Consumer LCC Impacts						
Design line 6						
Net Cost (%)	0.0	71.5	17.6	36.2	36.2	93.4
Net Benefit (%)	0.0	28.5	82.4	63.8	63.8	6.6
No Impact (%)	100.0	0.0	0.0	0.0	0.0	0.0
Design line 7						
Net Cost (%)	1.8	1.8	2.0	3.7	3.7	46.4
Net Benefit (%)	98.2	98.2	98.0	96.3	96.3	53.6
No Impact (%)	0.0	0.0	0.0	0.0	0.0	0.0
Design line 8						
Net Cost (%)	5.2	5.2	15.3	10.5	78.5	78.5
Net Benefit (%)	94.8	94.8	84.7	89.5	21.5	21.5
No Impact (%)	0.0	0.0	0.0	0.0	0.0	0.0

First, DOE considered TSL 6, the most efficient level (max tech), which would save an estimated total of 2.08 quads of energy through 2045, an amount DOE considers significant. TSL 6 has an estimated NPV of customer benefit of −$2.41 billion using a 7 percent discount rate, and $2.69 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 6 are 148 million metric tons of CO_2, 121 thousand tons of NO_X, and 0.992 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 6 ranges from $866 million to $15,427 million.

At TSL 6, the average LCC impact ranges from −$2,812 for design line 8 to $270 for design line 7. The median PBP ranges from 32.4 years for design line 6 to 18.1 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 6.6 percent for design line 6 to 53.6 percent for design line 7.

At TSL 6, the projected change in INPV ranges from a decrease of $83 million to an increase of $102 million. If the decrease of $83 million occurs, TSL 6 could result in a net loss of 37.9 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 6, DOE recognizes the risk of very large negative impacts on the industry. TSL 6 would require manufacturers to scrap nearly all production assets and create transformer designs with which most, if not all, have no experience. DOE is concerned, in particular, about large impacts on small businesses, which may not be able to procure sufficient volume of amorphous steel at competitive prices, if at all.

The Secretary tentatively concludes that, at TSL 6 for low-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the economic burden on customers (as indicated by negative average LCC savings, large PBPs, and the large percentage of customers who would experience LCC increases at design line 6 and design line 8), the potential for very large negative impacts on the manufacturers, and the potential burden on small manufacturers. Consequently, DOE has tentatively concluded that TSL 6 is not economically justified.

Next, DOE considered TSL 5, which would save an estimated total of 1.90 quads of energy through 2045, an amount DOE considers significant. TSL 5 has an estimated NPV of customer benefit of $1.37 billion using a 7 percent discount rate, and $9.37 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 5 are 139 million metric tons of CO_2, 114 thousand tons of NO_X, and 0.934 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $814 million to $14,517 million.

At TSL 5, the average LCC impact ranges from −$2,812 for design line 8 to $2,270 for design line 7. The median PBP ranges from 24.5 years for design line 8 to 6.9 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 21.5 percent for design line 8 to 96.3 percent for design line 7.

At TSL 5, the projected change in INPV ranges from a decrease of $55 million to an increase of $44 million. If the decrease of $55 million occurs, TSL 5 could result in a net loss of 25.2 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 5, DOE recognizes the risk of very large negative impacts on the industry. TSL 5 would require manufacturers to scrap nearly all production assets and create transformer designs with which most, if not all, have no experience. DOE is concerned, in particular, about large impacts on small businesses, which may not be able to procure sufficient volume of amorphous steel at competitive prices, if at all.

The Secretary tentatively concludes that, at TSL 5 for low-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the economic burden on customers at design line 8 (as indicated by negative average LCC savings, large PBPs, and the large percentage of customers who would experience LCC increases), the potential for very large negative impacts on the manufacturers, and the potential burden on small manufacturers. Consequently, DOE has tentatively concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated total of 1.86 quads of energy through 2045, an amount DOE considers significant. TSL 4 has an estimated NPV of customer benefit of $2.36 billion using a 7 percent discount rate, and $11.16 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 4 are 137 million metric tons of CO_2, 112 thousand tons of NO_X, and 0.918 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $800 million to $14,264 million.

At TSL 4, the average LCC impact ranges from $187 for design line 6 to $4,145 for design line 8. The median PBP ranges from 16.3 years for design line 6 to 6.9 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 63.8 percent for design line 6 to 96.3 percent for design line 7.

At TSL 4, the projected change in INPV ranges from a decrease of $46 million to an increase of $31 million. If the decrease of $46 million occurs, TSL 4 could result in a net loss of 21 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 4, DOE recognizes the risk of very large negative impacts on the industry. As with the higher TSLs, TSL 4 would require manufacturers to scrap nearly all production assets and create transformer designs with which most, if not all, have no experience. DOE is concerned, in particular, about large impacts on small businesses, which may not be able to procure sufficient volume of amorphous steel at competitive prices, if at all.

The Secretary tentatively concludes that, at TSL 4 for low-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the potential for very large negative impacts on the manufacturers, and the potential burden on small manufacturers. Consequently, DOE has tentatively concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3, which would save an estimated total of 1.29 quads of energy through 2045, an amount DOE considers significant. TSL 3 has an estimated NPV of customer benefit of $2.03 billion using a 7 percent discount rate, and $8.51 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 3 are 96.0 million metric tons of CO_2, 78.4 thousand tons of NO_X, and 0.645 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $562 million to $10,020 million.

At TSL 3, the average LCC impact ranges from $335 for design line 6 to $2,625 for design line 8. The median PBP ranges from 13.0 years for design line 6 to 4.7 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 82.4 percent for design line 6 to 98.0 percent for design line 7.

At TSL 3, the projected change in INPV ranges from a decrease of $27 million to an increase of $20 million. If the decrease of $27 million occurs, TSL 3 could result in a net loss of 12.2 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 3, DOE recognizes the risk of negative impacts on the industry, particularly the small manufacturers. While TSL 3 could likely be met with M4 steel, DOE's analysis shows that this design option is at the edge of its technical feasibility at the efficiency levels comprised by TSL 3. Although these levels could be met with M3 or better steels, DOE is concerned that a significant number of small manufacturers would be unable to acquire these steels in sufficient supply and quality to compete. Additionally, TSL 3 requires significant investment in advanced core construction equipment such are step-lap mitering machines or wound core production lines, as butt lap designs, even with high-grade designs, are unlikely to comply. Given their more limited engineering resources and capital, small businesses may find it difficult to make these designs at competitive prices and may have to exit the market. At the same time, however, those small manufacturers may be able to source their cores—and many are doing so to a significant extent currently—which could mitigate impacts.

The Secretary tentatively concludes that, at TSL 3 for low-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the risk of negative impacts on the industry, particularly the small manufacturers. Consequently, DOE has tentatively concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2, which would save an estimated total of 1.12 quads of energy through 2045, an amount DOE considers significant. TSL 2 has an estimated NPV of customer benefit of $1.97 billion using a 7 percent discount rate, and $7.79 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 2 are 83.9 million metric tons of CO_2, 68.6 thousand tons of NO_X, and 0.564 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 2 ranges from $492 million to $8,764 million.

At TSL 2, the average LCC impact ranges from −$125 for design line 6 to $2,476 for design line 8. The median PBP ranges from 24.7 years for design line 6 to 4.5 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 28.5 percent for design line 6 to 98.2 percent for design line 7.

At TSL 2, the projected change in INPV ranges from a decrease of $20 million to an increase of $15 million. If the decrease of $20 million occurs, TSL 2 could result in a net loss of 8.9 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 2, DOE recognizes the risk of negative impacts on the industry, particularly small manufacturers. TSL 2 would likely require mitering or wound core technology, which many small businesses do not have in-house. Given their more limited engineering resources and capital, small businesses may find it difficult to make these designs at competitive prices and may have to exit the market. At the same time, however, those small manufacturers may be able to source their cores—and many are doing so to a significant extent currently—which could mitigate impacts.

The Secretary tentatively concludes that, at TSL 2 for low-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average LCC savings, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the risk of negative impacts on the industry, particularly regarding the uncertainty over how small businesses would be impacted. Consequently, DOE has tentatively concluded that TSL 2 is not economically justified.

Next, DOE considered TSL 1, which would save an estimated total of 1.09 quads of energy through 2045, an amount DOE considers significant. TSL 1 has an estimated NPV of customer benefit of $2.03 billion using a 7 percent discount rate, and $7.81 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 1 are 82.1 million metric tons of CO_2, 67.0 thousand tons of NO_X, and 0.551 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 1 ranges from $481 million to $8,570 million.

At TSL 1, the average LCC impact ranges from $1,714 for design line 7 to $2,476 for design line 8. The median PBP ranges from 8.4 years for design line 8 to 4.5 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 94.8 percent for design line 8 to 98.2 percent for design line 7.

At TSL 1, the projected change in INPV ranges from a decrease of $17 million to an increase of $17 million. If the decrease of $17 million occurs, TSL 1 could result in a net loss of 7.7 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 1, DOE recognizes the risk of small negative impacts on the industry if manufacturers are not able to recoup their investment costs. At this level, small manufacturers can still use butt-lap construction and steels with which they generally have experience.

After considering the analysis and weighing the benefits and the burdens, DOE has tentatively concluded that at TSL 1 for low-voltage, dry-type distribution transformers, the benefits of energy savings, NPV of customer benefit, positive customer LCC impacts, emissions reductions and the estimated monetary value of the emissions reductions would outweigh the risk of small negative impacts on the manufacturers. In particular, the Secretary has concluded that TSL 1 would save a significant amount of energy and is technologically feasible and economically justified. NEMA also recommended TSL 1 for low-voltage, dry-type distribution transformers during the negotiated rulemaking. For the reasons given above, DOE today proposes to adopt the energy conservation standards for low-voltage dry-type distribution transformers at TSL 1. Table V.42 presents the proposed energy conservation standards for low-voltage, dry-type distribution transformers.

TABLE V.42—PROPOSED ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS

Electrical efficiency by kVA and equipment class			
Equipment class 3		Equipment class 4	
kVA	%	kVA	%
15	97.73	15	97.44
25	98.00	30	97.95
37.5	98.20	45	98.20
50	98.31	75	98.47
75	98.50	112.5	98.66
100	98.60	150	98.78
167	98.75	225	98.92
250	98.87	300	99.02
333	98.94	500	99.17
		750	99.27
		1000	99.34

3. Benefits and Burdens of Trial Standard Levels Considered for Medium-Voltage, Dry-Type Distribution Transformers

Table V.43 and Table V.44 summarize the quantitative impacts estimated for each TSL for medium-voltage, dry-type distribution transformers.

TABLE V.43—SUMMARY OF ANALYTICAL RESULTS FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
National Energy Savings (*quads*)	0.06	0.13	0.23	0.23	0.37
NPV of Consumer Benefits (*2010$ billion*)					
3% discount rate	0.42	0.67	0.90	0.90	−0.38
7% discount rate	0.10	0.13	0.06	0.06	−0.84
Cumulative Emissions Reduction					
CO_2 (million metric tons)	4.62	8.80	16.8	16.8	25.7
NO_X (thousand tons)	3.77	7.19	13.7	13.7	21.0
Hg (*tons*)	0.031	0.059	0.113	0.113	0.173
Value of Emissions Reduction					
CO_2 (2010$ million)*	27 to 483	52 to 919	98 to 1751	98 to 1751	151 to 2688
NO_X—3% discount rate (*2010$ million*)	1 to 15	3 to 28	5 to 53	5 to 53	8 to 82
NO_X—7% discount rate (*2010$ million*)	0 to 5	1 to 9	2 to 17	2 to 17	3 to 27

* Range of the economic value of CO_2 reductions is based on estimates of the global benefit of reduced CO_2 emissions.

TABLE V.44—SUMMARY OF ANALYTICAL RESULTS FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Manufacturer Impacts					
Industry NPV (2011$ million)	87 to 89	85 to 90	80 to 95	77 to 93	71 to 114
Industry NPV (% change)	(4.2) to (2.0)	(7.1) to (1.0)	(12.4) to 4.5	(15.3) to 1.7	(21.9) to 25.4
Consumer Mean LCC Savings (2010$)					
Design line 9	849	1659	1659	1659	237
Design line 10	4509	4791	4791	4791	−12756
Design line 11	1043	202	2000	2000	−3160
Design line 12	4518	6332	8860	8860	−12420
Design line 13A	25	447	−846	−846	−11077
Design line 13B	2734	−961	384	384	−5403
Consumer Median PBP (years)					
Design line 9	2.6	6.2	6.2	6.2	19.1
Design line 10	1.1	8.8	8.8	8.8	28.4
Design line 11	10.7	17.6	14.1	14.1	24.5
Design line 12	6.3	13.5	13.0	13.0	25.9
Design line 13A	16.5	16.6	21.7	21.7	37.1
Design line 13B	4.6	20.4	19.3	19.3	21.9
Distribution of Consumer LCC Impacts					
Design line 9					
Net Cost (%)	3.4	5.7	5.7	5.7	53.4
Net Benefit (%)	83.4	94.3	94.3	94.3	46.6
No Impact (%)	13.3	0.0	0.0	0.0	0.0
Design line 10					
Net Cost (%)	0.7	16.7	16.7	16.7	84.8
Net Benefit (%)	98.8	83.3	83.3	83.3	15.2
No Impact (%)	0.5	0.0	0.0	0.0	0.0
Design line 11					
Net Cost (%)	20.6	49.5	25.7	25.7	76.1
Net Benefit (%)	79.4	50.5	74.3	74.3	23.9
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Design line 12					
Net Cost (%)	6.7	23.5	18.1	18.1	81.1
Net Benefit (%)	93.3	76.5	81.9	81.9	18.9
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Design line 13A					
Net Cost (%)	52.2	42.3	64.4	64.4	97.1
Net Benefit (%)	47.8	57.7	35.6	35.6	2.9
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Design line 13B					
Net Cost (%)	28.5	59.6	52.7	52.7	67.2
Net Benefit (%)	71.3	40.4	47.3	47.3	32.8
No Impact (%)	0.2	0.0	0.0	0.0	0.0

First, DOE considered TSL 5, the most efficient level (max tech), which would save an estimated total of 0.37 quads of energy through 2045, an amount DOE considers significant. TSL 5 has an estimated NPV of customer benefit of −$0.84 billion using a 7 percent discount rate, and −$0.38 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 5 are 25.7 million metric tons of CO_2, 21.0 thousand tons of NO_X, and 0.173 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $151 million to $2,688 million.

At TSL 5, the average LCC impact ranges from −$12,756 for design line 10 to −$237 for design line 9. The median PBP ranges from 37.1 years for design line 13A to 19.1 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 2.9 percent for design line 13A to 46.6 percent for design line 9.

At TSL 5, the projected change in INPV ranges from a decrease of $20 million to an increase of $23 million. If the decrease of $20 million occurs, TSL 5 could result in a net loss of 21.9 percent in INPV to manufacturers of medium-voltage dry-type distribution transformers. At TSL 5, DOE recognizes the risk of very large negative impacts on industry because they would likely be forced to move to amorphous technology, with which there is no experience in this market.

The Secretary tentatively concludes that, at TSL 5 for medium-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the negative NPV of customer benefit, the economic burden on customers (as indicated by negative average LCC savings, large PBPs, and the large percentage of customers who would experience LCC increases), and the risk of very large negative impacts on the manufacturers. Consequently, DOE has tentatively concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated total of 0.23 quads of energy through 2045, an amount DOE considers significant. TSL 4 has an estimated NPV of customer benefit of $0.06 billion using a 7 percent discount rate, and $0.90 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 4 are 16.8 million metric tons of CO_2, 13.7 thousand tons of NO_X, and 0.113 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $98 million to $1,751 million.

At TSL 4, the average LCC impact ranges from −$846 for design line 13A to $8,860 for design line 12. The median PBP ranges from 21.7 years for design line 13A to 6.2 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 35.6 percent for design line 13A to 94.3 percent for design line 9.

At TSL 4, the projected change in INPV ranges from a decrease of $14 million to an increase of $2 million. If the decrease of $14 million occurs, TSL 4 could result in a net loss of 15.3 percent in INPV to manufacturers of medium-voltage dry-type distribution transformers. At TSL 4, DOE recognizes the risk of very large negative impacts on most manufacturers in the industry who have little experience with the steels that would be required. Small businesses, in particular, with limited engineering resources, may not be able to convert their lines to employ thinner steels and may be disadvantaged with respect to access to key materials, including Hi-B steels.

The Secretary tentatively concludes that, at TSL 4 for medium-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive impacts on consumers (as indicated by positive average LCC savings, favorable PBPs, and the large percentage of customers who would experience LCC benefits), emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the risk of very large negative impacts on the manufacturers, particularly small businesses. Consequently, DOE has tentatively concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3, which would save an estimated total of 0.23 quads of energy through 2045, an amount DOE considers significant. TSL 3 has an estimated NPV of customer benefit of $0.06 billion using a 7 percent discount rate, and $0.90 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 3 are 16.8 million metric tons of CO_2, 13.7 thousand tons of NO_X, and 0.113 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $98 million to $1,751 million.

At TSL 3, the average LCC impact ranges from −$846 for design line 13A to $8,860 for design line 12. The median PBP ranges from 21.7 years for design line 13A to 6.2 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 35.6 percent for design line 13A to 94.3 percent for design line 9.

At TSL 3, the projected change in INPV ranges from a decrease of $11 million to an increase of $4 million. If the decrease of $11 million occurs, TSL 3 could result in a net loss of 12.4 percent in INPV to manufacturers of medium-voltage dry-type transformers. At TSL 3, DOE recognizes the risk of large negative impacts on most manufacturers in the industry who have little experience with the steels that would be required. As with TSL 4, small businesses, in particular, with limited engineering resources, may not be able to convert their lines to employ thinner steels and may be disadvantaged with respect to access to key materials, including Hi-B steels.

The Secretary tentatively concludes that, at TSL 3 for medium-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive impacts on consumers (as indicated by positive average LCC savings, favorable PBPs, and the large percentage of customers who would experience LCC benefits), emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the risk of large negative impacts on the manufacturers, particularly small businesses. Consequently, DOE has tentatively concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2, which would save an estimated total of 0.13 quads of energy through 2045, an amount DOE considers significant. TSL 2 has an estimated NPV of customer benefit of $0.10 billion using a 7 percent discount rate, and $0.42 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 2 are 8.80 million metric tons of CO_2, 7.19 thousand tons of NO_X, and 0.059 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 2 ranges from $52 million to $919 million.

At TSL 2, the average LCC impact ranges from −$961 for design line 13B to $6,332 for design line 12. The median PBP ranges from 20.4 years for design line 13B to 6.2 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 40.4 percent for design line 13B to 94.3 percent for design line 9.

At TSL 2, the projected change in INPV ranges from a decrease of $7 million to a decrease of $1 million. If the decrease of $7 million occurs, TSL 2 could result in a net loss of 7.1 percent in INPV to manufacturers of medium-voltage dry-type distribution transformers. At TSL 2, DOE recognizes the risk of small negative impacts if manufacturers are unable to recoup investments made to meet the standard.

After considering the analysis and weighing the benefits and the burdens, DOE has tentatively concluded that at TSL 2 for medium-voltage, dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive impacts on consumers (as indicated by positive average LCC savings for five of the six design lines, favorable PBPs, and the large percentage of customers who would experience LCC benefits), emission reductions, and the estimated monetary value of the emissions reductions would outweigh the risk of small negative impacts if manufacturers are unable to recoup investments made to meet the standard. In particular, the Secretary of Energy has concluded that TSL 2 would save a significant amount of energy and is technologically feasible and economically justified. In addition, DOE notes that TSL 2 corresponds to the standards that were agreed to by the ERAC subcommittee, as described in section II.B.2. Based on the above considerations, DOE today proposes to adopt the energy conservation standards for medium-voltage, dry-type distribution transformers at TSL 2. Table V.45 presents the proposed energy conservation standards for medium-voltage, dry-type distribution transformers.

TABLE V.45—PROPOSED ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS

Electrical efficiency by kVA and equipment class											
Equipment class 5		Equipment class 6		Equipment class 7		Equipment class 8		Equipment class 9		Equipment class 10	
kVA	%	kVA	%	kVA	%	kVA	%	kVA	%	kVA	%
15	98.10	15	97.50	15	97.86	15	97.18	....	....	....	....
25	98.33	30	97.90	25	98.12	30	97.63	....	....	....	....
37.5	98.49	45	98.10	37.5	98.30	45	97.86	....	....	....	....
50	98.60	75	98.33	50	98.42	75	98.13	....	....	....	....
75	98.73	112.5	98.52	75	98.57	112.5	98.36	75	98.53	....	....
100	98.82	150	98.65	100	98.67	150	98.51	100	98.63	....	....
167	98.96	225	98.82	167	98.83	225	98.69	167	98.80	225	98.57
250	99.07	300	98.93	250	98.95	300	98.81	250	98.91	300	98.69
333	99.14	500	99.09	333	99.03	500	98.99	333	98.99	500	98.89
500	99.22	750	99.21	500	99.12	750	99.12	500	99.09	750	99.02
667	99.27	1000	99.28	667	99.18	1000	99.20	667	99.15	1000	99.11
833	99.31	1500	99.37	833	99.23	1500	99.30	833	99.20	1500	99.21
		2000	99.43	....	....	2000	99.36	....	....	2000	99.28
		2500	99.47	....	....	2500	99.41	....	....	2500	99.33

4. Summary of Benefits and Costs (Annualized) of the Proposed Standards

The benefits and costs of today's proposed standards can also be expressed in terms of annualized values. The annualized monetary values are the sum of (1) the annualized national economic value of the benefits from operating products that meet the proposed standards (consisting primarily of operating cost savings from using less energy, minus increases in equipment purchase costs, which is another way of representing customer NPV), and (2) the monetary value of the benefits of emission reductions, including CO_2 emission reductions.[43] The value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 developed by a recent interagency process.

Although combining the values of operating savings and CO_2 reductions provides a useful perspective, two issues should be considered. First, the national operating savings are domestic U.S. customer monetary savings that occur as a result of market transactions while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and SCC are performed with different methods that use different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2016–2045. The SCC values, on the other hand, reflect the present value of future climate-related impacts resulting from the emission of one metric ton of CO_2 in each year. These impacts continue well beyond 2100.

Table V.46 shows the annualized values for the proposed standards for distribution transformers. The results for the primary estimate are as follows. Using a 7-percent discount rate for benefits and costs other than CO_2 reductions, for which DOE used a 3-percent discount rate along with the SCC series corresponding to a value of $22.3/metric ton in 2010, the cost of the standards proposed in today's rule is $302 million per year in increased product costs, while the annualized benefits are $631 million in reduced product operating costs, $244 million in CO_2 reductions, and $7.78 million in reduced NO_X emissions. In this case, the net benefit amounts to $581 million per year. Using a 3-percent discount rate for all benefits and costs and the SCC series corresponding to a value of $22.3/metric ton in 2010, the cost of the standards proposed in today's rule is $308 million per year in increased product costs, while the annualized benefits are $1,026 million in reduced operating costs, $244 million in CO_2 reductions, and $12.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $975 million per year.

TABLE V.46—ANNUALIZED BENEFITS AND COSTS OF PROPOSED STANDARDS FOR DISTRIBUTION TRANSFORMERS SOLD IN 2016–2045

	Discount rate	Monetized (million 2010$/year)		
		Primary estimate*	Low net benefits estimate*	High net benefits estimate*
Benefits				
Operating Cost Savings	7%	631	594	659
	3%	1,026	950	1,075
CO_2 Reduction at $4.9/t**	5%	58.6	58.6	58.6

[43] DOE used a two-step calculation process to convert the time-series of costs and benefits into annualized values. First, DOE calculated a present value in 2011, the year used for discounting the NPV of total consumer costs and savings, for the time-series of costs and benefits using discount rates of 3 and 7 percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE used a range of discount rates, as shown in Table V.46. From the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in 2011 that yields the same present value. The fixed annual payment is the annualized value. Although DOE calculated annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined would be a steady stream of payments.

TABLE V.46—ANNUALIZED BENEFITS AND COSTS OF PROPOSED STANDARDS FOR DISTRIBUTION TRANSFORMERS SOLD IN 2016–2045—Continued

	Discount rate	Monetized (million 2010$/year)		
		Primary estimate*	Low net benefits estimate*	High net benefits estimate*
CO_2 Reduction at $22.3/t**	3%	244	244	244
CO_2 Reduction at $36.5/t**	2.5%	389	389	389
CO_2 Reduction at $67.6/t**	3%	742	742	742
NO_X Reduction at $2,537/ton**	7%	7.78	7.78	7.78
	3%	12.4	12.4	12.4
Total †	7% plus CO_2 range	697 to 1380	660 to 1343	726 to 1409
	7%	883	846	911
	3% plus CO_2 range	1097 to 1780	1021 to 1704	1146 to 1829
	3%	1,283	1,207	1,331
Costs				
Incremental Product Costs	7%	302	338	285
	3%	308	351	289
Total Net Benefits				
Total †	7% plus CO_2 range	400 to 1083	327 to 1010	445 to 1128
	7%	581	507	626
	3% plus CO_2 range	789 to 1472	670 to 1353	857 to 1540
	3%	975	855	1,043

* The Primary, Low Net Benefits, and High Net Benefits Estimates utilize forecasts of energy prices from the AEO 2011 reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect no change in the Primary estimate, rising product prices in the Low Net Benefits estimate, and declining product prices in the High Net Benefits estimate.

** The CO_2 values represent global values (in 2010$) of the social cost of CO_2 emissions in 2010 under several scenarios. The values of $4.9, $22.3, and $36.5 per metric ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6 per metric ton represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The value for NO_X (in 2010$) is the average of the low and high values used in DOE's analysis.

† Total Benefits for both the 3% and 7% cases are derived using the SCC value calculated at a 3% discount rate, which is $22.3/metric ton in 2010 (in 2010$). In the rows labeled as ''7% plus CO_2 range'' and ''3% plus NO_X range,'' the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Orders 12866 and 13563

Section 1(b)(1) of Executive Order 12866, ''Regulatory Planning and Review,'' 58 FR 51735 (Oct 4, 1993), requires each agency to identify the problem that it intends to address, including, where applicable, the failures of private markets or public institutions that warrant new agency action, as well as to assess the significance of that problem. The problems that today's proposed standards address are as follows:

(1) There is a lack of consumer information and/or information processing capability about energy efficiency opportunities in the commercial equipment market.

(2) There is asymmetric information (one party to a transaction has more and better information than the other) and/or high transactions costs (costs of gathering information and effecting exchanges of goods and services).

(3) There are external benefits resulting from improved energy efficiency of distribution transformers that are not captured by the users of such equipment. These benefits include externalities related to environmental protection and energy security that are not reflected in energy prices, such as reduced emissions of greenhouse gases.

The specific market failure that the energy conservation standard addresses for distribution transformers is that a substantial portion of distribution transformer purchasers are not evaluating the cost of transformer losses when they make distribution transformer purchase decisions. Therefore, distribution transformers are being purchased that do not provide the minimum LCC service to equipment owners.

For distribution transformers, the Institute of Electronic and Electrical Engineers Inc. (IEEE) has documented voluntary guidelines for the economic evaluation of distribution transformer losses, IEEE PC57.12.33/D8. These guidelines document economic evaluation methods for distribution transformers that are common practice in the utility industry. But while economic evaluation of transformer losses is common, it is not a universal practice. DOE collected information during the course of the previous energy conservation standard rulemaking to estimate the extent to which distribution transformer purchases are evaluated. Data received from the National Electrical Manufacturers Association indicated that these guidelines or similar criteria are applied to approximately 75 percent of liquid-immersed transformer purchases, 50 percent of small capacity medium-voltage dry-type transformer purchases, and 80 percent of large capacity medium-voltage dry-type transformer purchases. Therefore, 25 percent, 50 percent, and 20 percent of distribution transformer purchases do not have economic evaluation of transformer losses. These are the portions of the distribution transformer market in which there is market failure. Today's proposed energy conservation standards would eliminate from the market those distribution transformers designs that are purchased on a purely minimum first cost basis, but which would not likely be purchased by equipment buyers when the economic value of equipment losses are properly evaluated.

In addition, DOE has determined that today's regulatory action is an ''economically significant regulatory action'' under section 3(f)(1) of Executive Order 12866. Accordingly, section 6(a)(3) of the Executive Order requires that DOE prepare a regulatory impact analysis (RIA) on today's proposed rule and that the Office of Information and Regulatory Affairs (OIRA) in the Office of Management and

Budget (OMB) review this rule. DOE presented to OIRA for review the draft rule and other documents prepared for this rulemaking, including the RIA, and has included these documents in the rulemaking record. The assessments prepared pursuant to Executive Order 12866 can be found in the technical support document for this rulemaking.

DOE has also reviewed this regulation pursuant to Executive Order 13563. 76 FR 3281 (Jan. 21, 2011). EO 13563 is supplemental to and explicitly reaffirms the principles, structures, and definitions governing regulatory review established in Executive Order 12866. To the extent permitted by law, agencies are required by Executive Order 13563 to: (1) Propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

DOE emphasizes as well that Executive Order 13563 requires agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. In its guidance, the Office of Information and Regulatory Affairs has emphasized that such techniques may include identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes. For the reasons stated in the preamble, DOE believes that today's NOPR is consistent with these principles.

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis (IRFA) for any rule that by law must be proposed for public comment, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. As required by Executive Order 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (Aug. 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the rulemaking process. 68 FR 7990. DOE has made its procedures and policies available on the Office of the General Counsel's Web site (*www.gc.doe.gov*).

Based on the number of small distribution transformer manufacturers and the potential scope of the impact, DOE could not certify that the proposed standards would not have a significant impact on a significant number of small businesses in the distribution transformer industry. Therefore, DOE has prepared an IRFA for this rulemaking, a copy of which DOE will transmit to the Chief Counsel for Advocacy of the SBA for review under 5 U.S.C 605(b). As presented and discussed below, the IFRA describes potential impacts on small transformer manufacturers associated with capital and product conversion costs and discusses alternatives that could minimize these impacts.

A statement of the objectives of, and reasons and legal basis for, the proposed rule are set forth elsewhere in the preamble and not repeated here.

1. Description and Estimated Number of Small Entities Regulated

a. Methodology for Estimating the Number of Small Entities

For manufacturers of distribution transformers, the Small Business Administration (SBA) has set a size threshold, which defines those entities classified as ''small businesses'' for the purposes of the statute. DOE used the SBA's small business size standards to determine whether any small entities would be subject to the requirements of the rule. 65 FR 30836, 30850 (May 15, 2000), as amended at 65 FR 53533, 53545 (Sept. 5, 2000) and codified at 13 CFR part 121. The size standards are listed by North American Industry Classification System (NAICS) code and industry description and are available at *http://www.sba.gov/content/table-small-business-size-standards*. Distribution transformer manufacturing is classified under NAICS 335311, ''Power, Distribution and Specialty Transformer Manufacturing.'' The SBA sets a threshold of 750 employees or less for an entity to be considered as a small business for this category.

To estimate the number of companies that could be small business manufacturers of products covered by this rulemaking, DOE conducted a market survey using available public information to identify potential small manufacturers. DOE's research involved industry trade association membership directories (including NEMA), information from previous rulemakings, UL qualification directories, individual company Web sites, and market research tools (*e.g.,* Hoover's reports) to create a list of companies that potentially manufacture distribution transformers covered by this rulemaking. DOE also asked stakeholders and industry representatives if they were aware of any other small manufacturers during manufacturer interviews and at previous DOE public meetings. As necessary, DOE contacted companies on its list to determine whether they met the SBA's definition of a small business manufacturer. DOE screened out companies that do not offer products covered by this rulemaking, do not meet the definition of a ''small business,'' or are foreign owned and operated.

DOE initially identified at least 63 potential manufacturers of distribution transformers sold in the U.S. DOE reviewed publicly available information on these potential manufacturers and contacted many to determine whether they qualified as small businesses. Based on these efforts, DOE estimates there are 10 liquid immersed small business manufacturers, 14 LVDT small business manufacturers, and 17 small business manufacturers of MVDT. Some small businesses compete in more than one of these markets.

b. Manufacturer Participation

Of the LVDT manufacturers, DOE was able to reach and discuss potential standards with eight of the 14 small business manufacturers. Of the MVDT manufacturers, DOE was able to reach and discuss potential standards with five of the 17 small business manufacturers. Of the liquid-immersed small business manufacturers, DOE was able to reach and discuss potential standards with three of the 10 small business manufacturers. DOE also obtained information about small business impacts while interviewing large manufacturers.

c. Distribution Transformer Industry Structure and Nature of Competition

Liquid Immersed

Six major manufacturers supply more than 80 percent of the market for liquid-immersed transformers. None of the major manufacturers of distribution transformers covered in this rulemaking are considered to be small businesses. The vast majority of shipments are manufactured domestically. Electric utilities compose the customer base and typically buy on first-cost. Many small manufacturers position themselves towards the higher end of the market or in particular product niches, such as network transformers or harmonic mitigating transformers, but, in general, competition is based on price after a given unit's specs are prescribed by a customer.

Low-Voltage Dry-Type

Four major manufacturers supply more than 80 percent of the market for low-voltage dry-type transformers. None of the major LVDT manufacturers of distribution transformers covered in this rulemaking are small businesses. The customer base rarely purchases on efficiency and is very first-cost conscious, which, in turn, places a premium on economies of scale in manufacturing. DOE estimates approximately 80 percent of the market is served by imports, mostly from Canada and Mexico. Many of the small businesses that compete in the low-voltage dry-type market produce specialized transformers that are exempted from standards. Roughly 50 percent of the market by revenue is exempted from DOE standards. This market is much more fragmented than the one serving DOE-covered LVDT transformers.

In the DOE-covered LVDT market, low-volume manufacturers typically do not compete directly with large manufacturers using business models similar to those of their bigger rivals because scale disadvantages in purchasing and production are usually too great a barrier in this portion of the market. The exceptions to this rule are those companies that also compete in the medium-voltage market and, to some extent, are able to leverage that experience and production economies. More typically, low-volume manufacturers have focused their operations on one or two parts of the value chain—rather than all of it—and trained their sights on market segments outside of the high-volume baseline efficiency market.

In terms of operations, some small firms focus on the engineering and design of transformers and source the production of the cores or even the whole transformer, while other small firms focus on just production and rebrand for companies that offer broader solutions through their own sales and distribution networks.

In terms of market focus, many small firms simply compete entirely in the DOE-exempted markets. DOE did not attempt to contact companies operating entirely in this very fragmented market. Of those that do compete in the DOE-covered market, a few small businesses reported a focus on the high-end of the market, often selling NEMA Premium or better transformers as retrofit opportunities. Others focus on particular applications or other niches, like data centers, and become well-versed in the unique needs of a particular customer base.

Medium-Voltage Dry-Type

The medium-voltage dry-type transformer market is relatively consolidated with one large company holding a substantial share of the market. Electric utilities and industrial users make up most of the customer base and typically buy on first-cost or features other than efficiency. DOE estimates that at least 75 percent of production occurs domestically. Several manufacturers also compete in the power transformer market. Like the LVDT industry, most small business manufacturers often produce transformers exempted from DOE standards. DOE estimates 10 percent of the market is exempt from standards.

d. Comparison Between Large and Small Entities

Small distribution transformer manufacturers differ from large manufacturers in several ways that affect the extent to which they would be impacted by the proposed standards. Characteristics of small manufacturers include: lower production volumes, fewer engineering resources, less technical expertise, lack of purchasing power for high performance steels, and less access to capital.

Lower production volumes lie at the heart of most small business disadvantages, particularly for a small manufacturer that is vertically integrated. A lower-volume manufacturer's conversion costs would need to be spread over fewer units than a larger competitor. Thus, unless the small business can differentiate its product in some way that earns a price premium, the small business is a 'price taker' and experiences a reduction in profit per unit relative to the large manufacturer. Therefore, because much of the same equipment would need to be purchased by both large and small manufacturers in order to produce transformers (in-house) at higher TSLs, undifferentiated small manufacturers would face a greater variable cost penalty because they must depreciate the one-time conversion expenditures over fewer units.

Smaller companies are also more likely to have more limited engineering resources and they often operate with lower levels of design and manufacturing sophistication. Smaller companies typically also have less experience and expertise in working with more advanced technologies, such as amorphous core construction in the liquid immersed market or step-lap mitering in the dry-type markets. Standards that required these technologies could strain the engineering resources of these small manufacturers if they chose to maintain a vertically integrated business model.

Small distribution transformer manufacturers can also be at a disadvantage due to their lack of purchasing power for high performance materials. If more expensive steels are needed to meet standards and steel cost grows as a percentage of the overall product cost, small manufacturers who pay higher per pound prices would be disproportionately impacted.

Lastly, small manufacturers typically have less access to capital, which may be needed by some to cover the conversion costs associated with new technologies.

2. Description and Estimate of Compliance Requirements

Liquid Immersed. Based on interviews with manufacturers in the liquid-immersed market, DOE does not believe small manufacturers will face significant capital conversion costs at the levels proposed in today's rulemaking. DOE expects small manufacturers of liquid-immersed distribution transformers to continue to produce silicon steel cores, rather than invest in amorphous technology. While silicon steel designs capable of achieving TSL 1 would get larger, and thus reduce throughput, most manufacturers said the industry in general has substantial excess capacity due to the recent economic downturn. Therefore, DOE believes TSL 1 would not require the typical small manufacturer to invest in additional capital equipment. However, small manufacturers may incur some engineering and product design costs associated with re-optimizing their production processes around new baseline products. DOE estimates TSL 1 would require industry production development costs of only one-half of one year's annual industry R&D expenses, as the levels do not require any changes in technology or steel types. Because these costs are relatively fixed per manufacturer, these one-time costs impact smaller manufacturers disproportionately compared to larger manufacturers. The table below illustrates this effect by comparing the conversion costs to a typical small company's and a typical large manufacturer's annual R&D expenses.

TABLE VI.1—ESTIMATED PRODUCT CONVERSION COSTS AS A PERCENTAGE OF ANNUAL R&D EXPENSE

	Product conversion cost	Product conversion cost as a percentage of annual R&D expense
Typical Large Manufacturer	$1.4 M	20
Typical Small Manufacturer	$1.4 M	222

While the costs disproportionately impact small manufactures, the standard levels, as stated above, do not require small manufacturers to invest in entirely different production processes nor do they require steels or core construction techniques with which these manufacturers are not familiar. A range of design options would still be available.

Low-Voltage Dry-Type. For the low-voltage dry-type market, at TSL 1, the level proposed in today's notice, DOE estimates, capital conversion costs of $0.75 million and product conversion costs of $0.2 million for a typical small and large manufacturer, based on manufacturer interviews. Because of the largely fixed nature of these one-time conversion expenditures that distribution transformer manufacturers would incur as a result of standards, small manufacturers who choose to invest to maintain in-house production will likely be disproportionately impacted compared to large manufacturers. As Table VI.2 indicates, small manufacturers face a greater relative hurdle in complying with standards should they opt to continue to maintain core production in-house.

TABLE VI.2—ESTIMATED CAPITAL AND PRODUCT CONVERSION COSTS AS A PERCENTAGE OF ANNUAL CAPITAL EXPENDITURES AND R&D EXPENSE

	Capital conversion cost as a percentage of annual capital expenditures	Product conversion cost as a percentage of annual R&D expense	Total conversion cost as a percentage of annual EBIT
Large Manufacturer	40	11	17
Small Manufacturer	152	49	77

As demonstrated in the table above, the investments required to meet TSL 1, disproportionately impact small businesses. However, DOE's capital conversion costs estimates in the table above assume that small businesses are currently producing their cores in-house and will choose to do so in the future, rather than source them from third-party core manufactures who often have significant cost advantages through bulk steel purchasing power and greater production efficiencies due to higher volumes. As such, many small businesses DOE interviewed already source a large percentage of their cores and many indicated they expected such a strategy would be the low-cost option under higher standards.

Compared to higher TSLs, TSL 1 provides many more design paths for small manufacturers to comply. DOE's engineering analysis indicates manufacturers can continue to use the low-capital butt-lap core designs, meaning investment in mitering capability is not necessary to comply. Manufacturers can use higher-quality grain oriented steels in butt-lap designs to meet these proposed efficiency levels, source some or all cores, or invest in mitering capability. DOE notes that roughly half of the small business LVDT manufacturers DOE interviewed already have mitering capability. For all of the reasons discussed, DOE believes the capital expenditures it assumed for small businesses are likely conservative and that small businesses have a variety of technical and strategic paths to continue to compete in the market at TSL 1.

Medium-Voltage Dry-Type. Based on its engineering analysis and interviews, DOE expects relatively minor capital expenditures for the industry to meet TSL 2. DOE understands that the market is already standardized on step-lap mitering, so manufacturers will not need to make major investments for more advanced core construction. Furthermore, TSL 2 does not require a change to much thinner steels such as M3 or HO. The industry can use M4 and H1, thicker steels with which it has much more experience and which are easier to employ in the stacked-core production process that dominates the medium-voltage market. However, some investment will be required to maintain capacity as some manufacturers will likely migrate to more M4 and H1 steel from the slightly thicker M5, which is also common. Additionally, design options at TSL 2 typically have larger cores, also slowing throughput. Therefore, some manufacturers may need to invest in additional production equipment. Alternatively, depending on each company's availability capacity, manufacturers could employ addition production shifts, rather than invest in additional capacity.

For the medium-voltage dry-type market, at TSL 2, the level proposed in today's notice, DOE estimates capital conversion costs of $1.0 million and product conversion costs of $0.2 million for a typical small and large manufacturer that would need to expand mitering capacity to meet TSL 2. Table VI.3 illustrates the relative impacts on small and large manufacturers.

TABLE VI.3—ESTIMATED CAPITAL AND PRODUCT CONVERSION COSTS AS A PERCENTAGE OF ANNUAL CAPITAL EXPENDITURES AND R&D EXPENSE

	Capital conversion cost as a percentage of annual capital expenditures	Product conversion cost as a percentage of annual R&D expense	Total conversion cost as a percentage of annual EBIT
Large Manufacturer	43	7	14
Small Manufacturer	327	65	124

a. Summary of Compliance Impacts

The compliance impacts on small businesses are discussed above for low-voltage dry-type, medium-voltage dry-type, and liquid-filled distribution transformer manufacturers. Although the conversion costs required can be considered substantial for all companies, the impacts could be relatively greater for a typical small manufacturer because of much lower production volumes and the relatively fixed nature of the R&D and capital investments required.

DOE seeks comment on the potential impacts of amended standards on small distribution transformer manufacturers.

3. Duplication, Overlap, and Conflict With Other Rules and Regulations

DOE is not aware of any rules or regulations that duplicate, overlap, or conflict with the rule being considered today.

4. Significant Alternatives to the Proposed Rule

The discussion above analyzes impacts on small businesses that would result from the other TSLs DOE considered. Though TSLs lower than the proposed TSLs are expected to reduce the impacts on small entities, DOE is required by EPCA to establish standards that achieve the maximum improvement in energy efficiency that are technically feasible and economically justified, and result in a significant conservation of energy. Therefore, DOE rejected the lower TSLs.

In addition to the other TSLs being considered, the NOPR TSD includes a regulatory impact analysis in chapter 17. For distribution transformers, this report discusses the following policy alternatives: (1) Consumer rebates, (2) consumer tax credits, and (3) manufacturer tax credits. DOE does not intend to consider these alternatives further because they either are not feasible to implement or are not expected to result in energy savings as large as those that would be achieved by the standard levels under consideration.

DOE continues to seek input from businesses that would be affected by this rulemaking and will consider comments received in the development of any final rule.

5. Significant Issues Raised by Public Comments

DOE's MIA suggests that, while TSL1, TSL1, and TSL 2 presents greater difficulties for small businesses than lower levels in the liquid-immersed, LVDT, and MVDT superclasses, respectively, the impacts at higher TSLs would be greater. DOE expects that small businesses will generally be able to profitably compete at the TSL proposed in today's rulemaking. DOE's MIA is based on its interviews of both small and large manufacturers, and consideration of small business impacts explicitly enters into DOE's choice of the TSLs proposed in this NOPR.

DOE also notes that today's proposed standards can be met with a variety of materials, including multiple core steels and both copper and aluminum windings. Because the proposed TSLs can be met with a variety of materials, DOE does not expect that material availability issues will be a problem for the industry that results from this rulemaking.

ACEEE submitted a comment stating that small, medium-voltage dry-type manufacturers would not be forced out of business at higher standard levels because they could either install the necessary mitering equipment or purchase finished cores. (ACEEE, No. 127 at p. 9) DOE recognizes both of these possibilities. While DOE agrees that standard levels higher than TSL2 would not necessarily drivel small businesses from the market, there is much more uncertainty about whether traditional M-grade steels can be used at higher TSLs, which could disproportionately jeopardize many small manufacturers who have limited access to domain refined steels.

6. Steps DOE Has Taken to Minimize the Economic Impact on Small Manufacturers

In consideration of the benefits and burdens of standards, including the burdens posed to small manufacturers, DOE concluded TSL1 is the highest level that can be justified for liquid immersed and low-voltage dry-type transformers and TSL2 is the highest level that can be justified for medium-voltage, dry-type transformers. As explained in part 6 of the IRFA, ''Significant Alternatives to the Rule,'' DOE explicitly considered the impacts on small manufacturers of liquid immersed and dry-type transformers in selecting the TSLs proposed in today's rulemaking, rather than selecting a higher trial standard level. It is DOE's belief that levels at TSL3 or higher would place excessive burdens on small manufacturers of medium-voltage, dry-type transformers, as would TSL 2 or higher for liquid immersed and low-voltage dry-type transformers. Such burdens would include large product redesign costs and also operational problems associated with the extremely thin laminations of core steel that would be needed to meet these levels and advanced core construction equipment and tooling. For low-voltage dry-type specifically, TSL2 essentially eliminates butt-lap core designs and will therefore put more burden on small manufacturers than would TSL1. However, the differential impact on small businesses (versus large businesses) is expected to be lower in moving to TSL1 than in moving from TSL2 to TSL3 because of the likely need to employ step lap mitering or wound core designs. Similarly, for medium voltage dry-type, the steels and construction techniques likely to be used at TSL 2 are already commonplace in the market, whereas TSL 3 would likely trigger a more dramatic shift to thinner and more exotic steels, to which many small businesses have limited access. Lastly, DOE is confident that TSL1 for the liquid immersed market would not require small manufacturers to invest in amorphous technology, which could put them at a significant disadvantage.

Section VI.B above discusses how small business impacts entered into DOE's selection of today's proposed standards for distribution transformers. DOE made its decision regarding standards by beginning with the highest level considered and successively eliminating TSLs until it found a TSL that is both technologically feasible and economically justified, taking into account other EPCA criteria. Because DOE believes that the TSLs proposed are economically justified (including consideration of small business impacts), the reduced impact on small businesses that would have been realized in moving down to lower efficiency levels was not considered in DOE's decision (but the reduced impact on small businesses that is realized in moving down to TSL2 from TSL3 (in the case of medium-voltage dry-type) and TSL2 to TSL1 (in the case of liquid immersed and low-voltage dry-type) was explicitly considered in the weighing of benefits and burdens).

C. Review Under the Paperwork Reduction Act

Manufacturers of distribution transformers must certify to DOE that their products comply with any applicable energy conservation standards. In certifying compliance, manufacturers must test their products according to the DOE test procedures for distribution transformers, including any amendments adopted for those test procedures. DOE has established regulations for the certification and recordkeeping requirements for all covered consumer products and commercial equipment, including distribution transformers. (76 FR 12422 (March 7, 2011). The collection-of-information requirement for the certification and recordkeeping is subject to review and approval by OMB under the Paperwork Reduction Act (PRA). This requirement has been approved by OMB under OMB control number 1910–1400. Public reporting burden for the certification is estimated to average 20 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the PRA, unless that collection of information displays a currently valid OMB Control Number.

D. Review Under the National Environmental Policy Act of 1969

Pursuant to the National Environmental Policy Act (NEPA) of 1969, as amended (42 U.S.C. 4321 *et seq.*), DOE has determined that the proposed rule fits within the category of actions included in Categorical Exclusion (CX) B5.1 and otherwise meets the requirements for application of a CX. (See 10 CFR 1021.410(b) and Appendix B to Subpart D) The proposed rule fits within this category of actions because it is a rulemaking that establishes energy conservation standards for consumer products or industrial equipment, and for which none of the exceptions identified in CX B5.1(b) apply. Therefore, DOE has made a CX determination for this rulemaking, and DOE does not need to prepare an Environmental Assessment or Environmental Impact Statement for this proposed rule. DOE's CX determination for this proposed rule is available at *http://cxnepa.energy.gov*.

E. Review Under Executive Order 13132

Executive Order 13132, ''Federalism,'' 64 FR 43255 (Aug. 10, 1999) imposes certain requirements on Federal agencies formulating and implementing policies or regulations that preempt State law or that have Federalism implications. The Executive Order requires agencies to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and to carefully assess the necessity for such actions. The Executive Order also requires agencies to have an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications. On March 14, 2000, DOE published a statement of policy describing the intergovernmental consultation process it will follow in the development of such regulations. 65 FR 13735. EPCA governs and prescribes Federal preemption of State regulations as to energy conservation for the products that are the subject of today's proposed rule. States can petition DOE for exemption from such preemption to the extent, and based on criteria, set forth in EPCA. (42 U.S.C. 6297) No further action is required by Executive Order 13132.

F. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of new regulations, section 3(a) of Executive Order 12988, ''Civil Justice Reform,'' imposes on Federal agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; and (3) provide a clear legal standard for affected conduct rather than a general standard and promote simplification and burden reduction. 61 FR 4729 (Feb. 7, 1996). Section 3(b) of Executive Order 12988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, this proposed rule meets the relevant standards of Executive Order 12988.

G. Review Under the Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and Tribal governments and the private sector. Public Law 104–4, sec. 201 (codified at 2 U.S.C. 1531). For a proposed regulatory action likely to result in a rule that may cause the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in any one year (adjusted annually for inflation), section 202 of UMRA requires a Federal agency to publish a written statement that estimates the resulting costs, benefits, and other effects on the national economy. (2 U.S.C. 1532(a), (b)) The UMRA also requires a Federal agency to develop an effective process to permit timely input by elected officers of State, local, and Tribal governments on a proposed ''significant intergovernmental mandate,'' and requires an agency plan for giving notice and opportunity for timely input to potentially affected small governments before establishing any requirements that might significantly or uniquely affect small governments. On March 18, 1997, DOE published a statement of policy on its process for intergovernmental consultation under UMRA. 62 FR 12820. DOE's policy statement is also available at *www.gc.doe.gov*.

Although today's proposed rule does not contain a Federal intergovernmental mandate, it may require expenditures of $100 million or more on the private sector. Specifically, the proposed rule will likely result in a final rule that could require expenditures of $100 million or more. Such expenditures may include: (1) Investment in R&D and in capital expenditures by distribution transformer manufacturers in the years between the final rule and the compliance date for the new standards, and (2) incremental additional expenditures by consumers to purchase higher-efficiency distribution transformers, starting at the compliance date for the applicable standard.

Section 202 of UMRA authorizes a Federal agency to respond to the content requirements of UMRA in any other statement or analysis that accompanies the proposed rule. (2 U.S.C. 1532(c)) The content requirements of section 202(b) of UMRA relevant to a private sector mandate substantially overlap the economic analysis requirements that apply under section 325(o) of EPCA and Executive Order 12866. The **SUPPLEMENTARY INFORMATION** section of this NOPR and the ''Regulatory Impact Analysis'' chapter of the TSD for this proposed rule respond to those requirements.

Under section 205 of UMRA, the Department is obligated to identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a written statement under section 202 is required. 2 U.S.C. 1535(a). DOE is required to select from those alternatives the most cost-effective and least burdensome alternative that achieves the objectives of the proposed rule unless DOE publishes an explanation for doing otherwise, or the selection of such an alternative is inconsistent with law. As required by 42 U.S.C. 6295(d), (f), and (o), 6313(e), and 6316(a), today's proposed rule would establish energy conservation standards for distribution transformers that are designed to achieve the maximum improvement in energy efficiency that DOE has determined to be both technologically feasible and economically justified. A full discussion of the alternatives considered by DOE is presented in the ''Regulatory Impact Analysis'' section of the TSD for today's proposed rule.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This rule would not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 12630

DOE has determined that under Executive Order 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights'' 53 FR 8859 (March 18, 1988), this regulation would not result in any takings that might require compensation under the Fifth Amendment to the U.S. Constitution.

J. Review Under the Treasury and General Government Appropriations Act, 2001

Section 515 of the Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516, note) provides for Federal agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (February 22, 2002), and DOE's guidelines were published at 67 FR 62446 (October 7, 2002). DOE has reviewed today's NOPR under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13211

Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)), requires Federal agencies to prepare and submit to OIRA at OMB, a Statement of Energy Effects for any proposed significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgates or is expected to lead to promulgation of a final rule, and that: (1) Is a significant regulatory action under Executive Order 12866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy, or (3) is designated by the Administrator of OIRA as a significant energy action. For any proposed significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use.

DOE has tentatively concluded that today's regulatory action, which sets forth proposed energy conservation standards for distribution transformers, is not a significant energy action because the proposed standards are not likely to have a significant adverse effect on the supply, distribution, or use of energy, nor has it been designated as such by the Administrator at OIRA. Accordingly, DOE has not prepared a Statement of Energy Effects on the proposed rule.

L. Review Under the Information Quality Bulletin for Peer Review

On December 16, 2004, OMB, in consultation with the Office of Science and Technology Policy (OSTP), issued its Final Information Quality Bulletin for Peer Review (the Bulletin). 70 FR 2664 (January 14, 2005). The Bulletin establishes that certain scientific information shall be peer reviewed by qualified specialists before it is disseminated by the Federal Government, including influential scientific information related to agency regulatory actions. The purpose of the bulletin is to enhance the quality and credibility of the Government's scientific information. Under the Bulletin, the energy conservation standards rulemaking analyses are ''influential scientific information,'' which the Bulletin defines as scientific information the agency reasonably can determine will have, or does have, a clear and substantial impact on important public policies or private sector decisions. 70 FR 2667.

In response to OMB's Bulletin, DOE conducted formal in-progress peer reviews of the energy conservation standards development process and analyses and has prepared a Peer Review Report pertaining to the energy conservation standards rulemaking analyses. Generation of this report involved a rigorous, formal, and documented evaluation using objective criteria and qualified and independent reviewers to make a judgment as to the technical/scientific/business merit, the actual or anticipated results, and the productivity and management effectiveness of programs and/or projects. The ''Energy Conservation Standards Rulemaking Peer Review Report'' dated February 2007 has been disseminated and is available at the following Web site: *www1.eere.energy.gov/buildings/appliance_standards/peer_review.html*.

VII. Public Participation

A. Attendance at the Public Meeting

The time, date, and location of the public meeting are listed in the **DATES** and **ADDRESSES** sections at the beginning of this notice. If you plan to attend the public meeting, please notify Ms. Brenda Edwards at (202) 586–2945 or

Brenda.Edwards@ee.doe.gov. As explained in the **ADDRESSES** section, foreign nationals visiting DOE Headquarters are subject to advance security screening procedures. Please also note that anyone that wishes to bring a laptop computer into the Forrestal Building will be required to obtain a property pass. Otherwise, visitors should avoid bringing laptops, or allow an extra 45 minutes.

In addition, you can attend the public meeting via webinar. Webinar registration information, participant instructions, and information about the capabilities available to webinar participants will be published on DOE's Web site at: *http://www1.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html*. Participants are responsible for ensuring their systems are compatible with the webinar software.

All documents in the docket are listed in the *www.regulations.gov* index. However, not all documents listed in the index may be publicly available, such as information that is exempt from public disclosure. The regulations.gov web page will contain simple instructions on how to access all documents, including public comments, in the docket. See section B for further information on how to submit comments through *www.regulations.gov*.

B. Procedure for Submitting Prepared General Statements for Distribution

Any person who has plans to present a prepared general statement may request that copies of his or her statement be made available at the public meeting. Such persons may submit requests, along with an advance electronic copy of their statement in PDF (preferred), Microsoft Word or Excel, WordPerfect, or text (ASCII) file format, to the appropriate address shown in the **ADDRESSES** section at the beginning of this notice. The request and advance copy of statements must be received at least one week before the public meeting and may be emailed, hand-delivered, or sent by mail. DOE prefers to receive requests and advance copies via email. Please include a telephone number to enable DOE staff to make follow-up contact, if needed.

C. Conduct of the Public Meeting

DOE will designate a DOE official to preside at the public meeting and may also use a professional facilitator to aid discussion. The meeting will not be a judicial or evidentiary-type public hearing, but DOE will conduct it in accordance with section 336 of EPCA (42 U.S.C. 6306). A court reporter will be present to record the proceedings and prepare a transcript. DOE reserves the right to schedule the order of presentations and to establish the procedures governing the conduct of the public meeting. After the public meeting, interested parties may submit further comments on the proceedings as well as on any aspect of the rulemaking until the end of the comment period.

The public meeting will be conducted in an informal, conference style. DOE will present summaries of comments received before the public meeting, allow time for prepared general statements by participants, and encourage all interested parties to share their views on issues affecting this rulemaking. Each participant will be allowed to make a general statement (within time limits determined by DOE), before the discussion of specific topics. DOE will allow, as time permits, other participants to comment briefly on any general statements.

At the end of all prepared statements on a topic, DOE will permit participants to clarify their statements briefly and comment on statements made by others. Participants should be prepared to answer questions by DOE and by other participants concerning these issues. DOE representatives may also ask questions of participants concerning other matters relevant to this rulemaking. The official conducting the public meeting will accept additional comments or questions from those attending, as time permits. The presiding official will announce any further procedural rules or modification of the above procedures that may be needed for the proper conduct of the public meeting.

A transcript of the public meeting will be included in the docket, which can be viewed as described in the *Docket* section at the beginning of this notice. In addition, any person may buy a copy of the transcript from the transcribing reporter.

D. Submission of Comments

DOE will accept comments, data, and information regarding this proposed rule before or after the public meeting, but no later than the date provided in the **DATES** section at the beginning of this proposed rule. Interested parties may submit comments, data, and other information using any of the methods described in the **ADDRESSES** section at the beginning of this notice.

Submitting comments via regulations.gov. The regulations.gov web page will require you to provide your name and contact information. Your contact information will be viewable to DOE Building Technologies staff only. Your contact information will not be publicly viewable except for your first and last names, organization name (if any), and submitter representative name (if any). If your comment is not processed properly because of technical difficulties, DOE will use this information to contact you. If DOE cannot read your comment due to technical difficulties and cannot contact you for clarification, DOE may not be able to consider your comment.

However, your contact information will be publicly viewable if you include it in the comment itself or in any documents attached to your comment. Any information that you do not want to be publicly viewable should not be included in your comment, nor in any document attached to your comment. Persons viewing comments will see only first and last names, organization names, correspondence containing comments, and any documents submitted with the comments.

Do not submit to regulations.gov information for which disclosure is restricted by statute, such as trade secrets and commercial or financial information (hereinafter referred to as Confidential Business Information (CBI)). Comments submitted through regulations.gov cannot be claimed as CBI. Comments received through the Web site will waive any CBI claims for the information submitted. For information on submitting CBI, see the Confidential Business Information section below.

DOE processes submissions made through regulations.gov before posting. Normally, comments will be posted within a few days of being submitted. However, if large volumes of comments are being processed simultaneously, your comment may not be viewable for up to several weeks. Please keep the comment tracking number that regulations.gov provides after you have successfully uploaded your comment.

Submitting comments via email, hand delivery/courier, or mail. Comments and documents submitted via email, hand delivery, or mail also will be posted to regulations.gov. If you do not want your personal contact information to be publicly viewable, do not include it in your comment or any accompanying documents. Instead, provide your contact information in a cover letter. Include your first and last names, email address, telephone number, and optional mailing address. The cover letter will not be publicly viewable as long as it does not include any comments.

Include contact information each time you submit comments, data, documents, and other information to DOE. If you submit via mail or hand delivery/courier, please provide all items on a CD, if feasible. It is not necessary to submit printed copies. No facsimiles (faxes) will be accepted.

Comments, data, and other information submitted to DOE electronically should be provided in PDF (preferred), Microsoft Word or Excel, WordPerfect, or text (ASCII) file format. Provide documents that are not secured, that are written in English, and that are free of any defects or viruses. Documents should not contain special characters or any form of encryption and, if possible, they should carry the electronic signature of the author.

Campaign form letters. Please submit campaign form letters by the originating organization in batches of between 50 to 500 form letters per PDF or as one form letter with a list of supporters' names compiled into one or more PDFs. This reduces comment processing and posting time.

Confidential Business Information. According to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit via email, postal mail, or hand delivery/courier two well-marked copies: one copy of the document marked confidential including all the information believed to be confidential, and one copy of the document marked non-confidential with the information believed to be confidential deleted. Submit these documents via email or on a CD, if feasible. DOE will make its own determination about the confidential status of the information and treat it according to its determination.

Factors of interest to DOE when evaluating requests to treat submitted information as confidential include: (1) A description of the items; (2) whether and why such items are customarily treated as confidential within the industry; (3) whether the information is generally known by or available from other sources; (4) whether the information has previously been made available to others without obligation concerning its confidentiality; (5) an explanation of the competitive injury to the submitting person which would result from public disclosure; (6) when such information might lose its confidential character due to the passage of time; and (7) why disclosure of the information would be contrary to the public interest.

It is DOE's policy that all comments may be included in the public docket, without change and as received, including any personal information provided in the comments (except information deemed to be exempt from public disclosure).

E. Issues on Which DOE Seeks Comment

Although DOE welcomes comments on any aspect of this proposal, DOE is particularly interested in receiving comments and views of interested parties concerning the following issues:

1. DOE requests comment on primary and secondary winding configurations, on how testing should be required, on efficiency differences related to different winding configurations, and on how frequently transformers are operated in various winding configurations.
2. DOE requests comment on its proposal to require transformers with multiple nameplate kVA ratings to comply only at those ratings corresponding to passive cooling.
3. DOE requests comment on its proposal to maintain the requirement that transformers comply with standards for the BIL rating of the configuration that produces the highest losses.
4. DOE requests comment on its proposal to maintain the current test loading value requirements for all types of distribution transformers.
5. DOE requests comment on its proposal to require rectifier and testing transformers to indicate on their nameplates that they are for such purposes exclusively.
6. DOE requests comment on its proposal to maintain the definition of mining transformer but also requests information useful in precisely expanding the definition to encompass any activity that entails the removal of material underground, such as digging or tunneling.
7. DOE requests comment on its proposal to maintain the current kVA scope of coverage.
8. DOE requests comment on its proposal to continue not to set standards for step-up transformers.
9. DOE requests comment on the negotiating committee's proposal to establish a separate equipment class for network/vault transformers and on how such transformers might be defined.
10. DOE requests comment on the negotiating committee's proposal to establish a separate equipment class for data center transformers and on how such transformers might be defined.
11. DOE seeks comment on the operating characteristics for data center transformers. Specifically DOE seeks comment on appropriate load factors, and peak responsibility factors of data center transformers.
12. DOE requests comment on whether separate equipment classes are warranted for pole-mounted, pad-mounted, or other types of liquid-immersed transformers.
13. DOE requests comment on setting standards by BIL rating for liquid-immersed distribution transformers as it currently does for medium-voltage, dry-type units.
14. DOE requests comment on how best to scale across phase counts for each transformer type and how standards for either single- or three-phase transformers may be derived from the other type.
15. DOE requests comment on its proposal to scale standards to unanalyzed kVA ratings by fitting a straight line in logarithmic space to selected efficiency levels (ELs) with the understanding that the resulting line may not have a slope equal to 0.75.
16. DOE seeks comment on symmetric core designs.
17. DOE seeks comment on nanotechnology composites and their potential for use in distribution transformers.
18. DOE requests comment on its materials prices for both 2010 and 2011 cases.
19. DOE requests comment on the current and future availabilities of high-grade steels, particularly amorphous and mechanically-scribed steel in the United States.
20. DOE requests comment on particular applications in which transformer size and weight are likely to be a constraint and any data that may be used to characterize the problem.
21. DOE requests comment on its steel supply availability analysis, presented in appendix 3A of the TSD.
22. DOE seeks comment on its proposed additional distribution channel for liquid-immersed transformers that estimates that approximately 80 percent of transformers are sold by manufacturers directly to utilities.
23. DOE seeks comment on any additional sources of distribution transformer load data that could be used to validate the Energy Use and End-Use Load Characterization analysis. DOE is specifically interested in additional load data for higher capacity three phase distribution transformers.
24. DOE seeks comment on its pole replacement methodology that is used estimate increased installation costs resulting from increased transformer weight due the proposed standard. The pole replacement methodology is presented in chapter 6, section 6.3.1 of the TSD.
25. DOE seeks comment on recent changes to utility distribution transformer purchase practices that would lead to the purchase of a

refurbished, specifically re-wound, distribution transformer over the purchase of new distribution transformer.

26. DOE seeks comment on the equipment lifetimes of refurbished, specifically re-wound distribution transformers and how it compares to that of a new distribution transformer.

27. DOE seeks comment on recent changes in distribution transformer sizing practices. In particular, DOE would like comments on any additional sources of data regarding trends in market share across equipment classes for either liquid-immersed or dry-type transformers that should be considered in the analysis.

28. DOE requests comment on the possibility of reduced equipment utility or performance resulting from today's proposed standards, particularly the risk of reducing the ability to perform periodic maintenance and the risk of increasing vibration and acoustic noise.

29. DOE requests comment and corroborating data on how often distribution transformers are operated with their primary and secondary windings in different configurations, and on the magnitude of the additional losses in less efficient configurations.

30. DOE requests comment on impedance values and on any related parameters (*e.g.,* inrush current, X/R ratio) that may be used in evaluation of distribution transformers. DOE requests particular comment on how any of those parameters may be affected by energy conservation standards of today's proposed levels or higher.

Approval of the Office of the Secretary

The Secretary of Energy has approved publication of today's proposed rule.

List of Subjects in 10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation, Household appliances, Imports, Intergovernmental relations, Reporting and recordkeeping requirements, and Small businesses.

Issued in Washington, DC, on January 31, 2012.

Henry Kelly,

Acting Assistant Secretary of Energy, Energy Efficiency and Renewable Energy.

For the reasons set forth in the preamble, DOE proposes to amend part 431 of chapter II, of title 10 of the Code of Federal Regulations, to read as set forth below:

PART 431—ENERGY EFFICIENCY PROGRAM FOR CERTAIN COMMERCIAL AND INDUSTRIAL EQUIPMENT

1. The authority citation for part 431 continues to read as follows:

Authority: 42 U.S.C. 6291–6317.

2. Revise § 431.196 to read as follows:

§ 431.196 Energy conservation standards and their effective dates.

(a) Low-Voltage Dry-Type Distribution Transformers. (1) The efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2007, but before January 1, 2016, shall be no less than that required for their kVA rating in the table below. Low-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	%	kVA	%
15	97.7	15	97.0
25	98.0	30	97.5
37.5	98.2	45	97.7
50	98.3	75	98.0
75	98.5	112.5	98.2
100	98.6	150	98.3
167	98.7	225	98.5
250	98.8	300	98.6
333	98.9	500	98.7
		750	98.8
		1000	98.9

Note: All efficiency values are at 35 percent of nameplate-rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, Subpart K, Appendix A.

(2) The efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2016, shall be no less than that required for their kVA rating in the table below. Low-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	%	kVA	%
15	97.73	15	97.44
25	98.00	30	97.95
37.5	98.20	45	98.20
50	98.31	75	98.47
75	98.50	112.5	98.66
100	98.60	150	98.78
167	98.75	225	98.92
250	98.87	300	99.02
333	98.94	500	99.17
		750	99.27

Single-phase		Three-phase	
kVA	%	kVA	%
		1000	99.34

Note: All efficiency values are at 35 percent of nameplate-rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, Subpart K, Appendix A.

(b) Liquid-Immersed Distribution Transformers. (1) The efficiency of a liquid-immersed distribution transformer manufactured on or after January 1, 2010, but before January 1, 2016, shall be no less than that required for their kVA rating in the table below. Liquid-immersed distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	%	kVA	%
10	98.70	15	98.65
15	98.82	30	98.83
25	98.95	45	98.92
37.5	99.05	75	99.03
50	99.11	112.5	99.11
75	99.19	150	99.16
100	99.25	225	99.23
167	99.33	300	99.27
250	99.39	500	99.35
333	99.43	750	99.40
500	99.49	1000	99.43
		1500	99.48

Note: All efficiency values are at 50 percent of nameplate-rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, Subpart K, Appendix A.

(2) The efficiency of a liquid-immersed distribution transformer manufactured on or after January 1, 2016, shall be no less than that required for their kVA rating in the table below. Liquid-immersed distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.62	15	98.36
15	98.76	30	98.62
25	98.91	45	98.76
37.5	99.01	75	98.91
50	99.08	112.5	99.01
75	99.17	150	99.08
100	99.23	225	99.17
167	99.25	300	99.23
250	99.32	500	99.25
333	99.36	750	99.32
500	99.42	1000	99.36
667	99.46	1500	99.42
833	99.49	2000	99.46
		2500	99.49

Note: All efficiency values are at 50 percent of nameplate-rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, Subpart K, Appendix A.

(c) Medium-Voltage Dry-Type Distribution Transformers. (1) The efficiency of a medium- voltage dry-type distribution transformer manufactured on or after January 1, 2010, but before January 1, 2016, shall be no less than that required for their kVA and BIL rating in the table below. Medium-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-Phase				Three-Phase			
BIL*	20–45 kV	46–95 kV	≥96 kV	BIL*	20–45 kV	46–95 kV	≥96 kV
kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)	kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.10	97.86		15	97.50	97.18	
25	98.33	98.12		30	97.90	97.63	
37.5	98.49	98.30		45	98.10	97.86	
50	98.60	98.42		75	98.33	98.13	
75	98.73	98.57	98.53	112.5	98.52	98.36	
100	98.82	98.67	98.63	150	98.65	98.51	
167	98.96	98.83	98.80	225	98.82	98.69	98.57
250	99.07	98.95	98.91	300	98.93	98.81	98.69
333	99.14	99.03	98.99	500	99.09	98.99	98.89
500	99.22	99.12	99.09	750	99.21	99.12	99.02
667	99.27	99.18	99.15	1000	99.28	99.20	99.11
833	99.31	99.23	99.20	1500	99.37	99.30	99.21
				2000	99.43	99.36	99.28
				2500	99.47	99.41	99.33

* BIL means basic impulse insulation level.

Note: All efficiency values are at 50 percent of nameplate rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, Subpart K, Appendix A.

(2) The efficiency of a medium-voltage dry-type distribution transformer manufactured on or after January 1, 2016, shall be no less than that required for their kVA and BIL rating in the table below. Medium-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-Phase				Three-Phase			
BIL*	20–45 kV	46–95 kV	≥96 kV	BIL*	20–45 kV	46–95 kV	≥96 kV
kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)	kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.10	97.86		15	97.50	97.18	
25	98.33	98.12		30	97.90	97.63	
37.5	98.49	98.30		45	98.10	97.86	
50	98.60	98.42		75	98.33	98.12	
75	98.73	98.57	98.53	112.5	98.49	98.30	
100	98.82	98.67	98.63	150	98.60	98.42	
167	98.96	98.83	98.80	225	98.73	98.57	98.53
250	99.07	98.95	98.91	300	98.82	98.67	98.63
333	99.14	99.03	98.99	500	98.96	98.83	98.80
500	99.22	99.12	99.09	750	99.07	98.95	98.91
667	99.27	99.18	99.15	1000	99.14	99.03	98.99
833	99.31	99.23	99.20	1500	99.22	99.12	99.09
				2000	99.27	99.18	99.15
				2500	99.31	99.23	99.20

* BIL means basic impulse insulation level.

Note: All efficiency values are at 50 percent of nameplate rated load, determined according to the DOE Test-Procedure. 10 CFR part 431, Subpart K, Appendix A.

(d) Underground Mining Distribution Transformers. [Reserved]

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