Friday,
August 4, 2006

Part II

Department of Energy

Office of Energy Efficiency and Renewable Energy

10 CFR Part 431

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

DEPARTMENT OF ENERGY

Office of Energy Efficiency and Renewable Energy

10 CFR Part 431

[Docket Number: EE–RM/STD–00–550]

RIN 1904–AB08

Energy Conservation Program for Commercial Equipment: Distribution Transformers Energy Conservation Standards

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 (EPCA or the Act) authorizes the Department of Energy (DOE or the Department) to establish energy conservation standards for various consumer products and commercial and industrial equipment, including those distribution transformers for which DOE determines that energy conservation standards would be technologically feasible and economically justified, and would result in significant energy savings. In this notice, the Department is proposing energy conservation standards for distribution transformers and is announcing a public meeting.

DATES: The Department will hold a public meeting on Wednesday, September 27, 2006, from 9 a.m. to 4 p.m., in Washington, DC. The Department must receive requests to speak at the public meeting before 4 p.m., Wednesday, September 13, 2006. The Department must receive a signed original and an electronic copy of statements to be given at the public meeting before 4 p.m., Wednesday, September 13, 2006.

The Department will accept comments, data, and information regarding the notice of proposed rulemaking (NOPR) before and after the public meeting, but no later than October 18, 2006. See section VII, ''Public Participation,'' of this NOPR for details.

ADDRESSES: The public meeting will be held at the U.S. Department of Energy, Forrestal Building, Room 1E245, 1000 Independence Avenue, SW., Washington, DC. (Please note that foreign nationals visiting DOE Headquarters are subject to advance security screening procedures, requiring a 30-day advance notice. If you are a foreign national and wish to participate in the workshop, please inform DOE of this fact as soon as possible by contacting Ms. Brenda Edwards-Jones at (202) 586–2945 so that the necessary procedures can be completed.)

You may submit comments, identified by docket number EE–RM/STD–00–550 and/or Regulatory Information Number (RIN) 1904–AB08, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *E-mail: TransformerNOPRComment@ee.doe.gov.* Include docket number EE–RM/STD–00–550 and/or RIN 1904–AB08 in the subject line of the message.
- *Mail:* Ms. Brenda Edwards-Jones, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J, NOPR for Distribution Transformers Energy Conservation Standards, docket number EE–RM/STD–00–550 and/or RIN 1904–AB08, 1000 Independence Avenue, SW., Washington, DC 20585–0121. Please submit one signed original paper copy.
- *Hand Delivery/Courier:* Ms. Brenda Edwards-Jones, U.S. Department of Energy, Building Technologies Program, Room 1J–018, 1000 Independence Avenue, SW., Washington, DC 20585. Telephone: (202) 586–2945. Please submit one signed original paper copy.

Instructions: All submissions received must include the agency name and docket number or RIN for this rulemaking. For detailed instructions on submitting comments and additional information on the rulemaking process, see section VII of this document (Public Participation).

Docket: For access to the docket to read background documents or comments received, visit the U.S. Department of Energy, Forrestal Building, Room 1J–018 (Resource Room of the Building Technologies Program), 1000 Independence Avenue, SW., Washington, DC, (202) 586–2945, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Please call Ms. Brenda Edwards-Jones at the above telephone number for additional information regarding visiting the Resource Room. **Please note:** The Department's Freedom of Information Reading Room (formerly Room 1E–190 at the Forrestal Building) is no longer housing rulemaking materials.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

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I. Summary of the Proposed Rule

Pursuant to the Energy Policy and Conservation Act, as amended, the Department is proposing energy conservation standards for liquid-immersed and medium-voltage, dry-type distribution transformers. The Department believes these standards will achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified, and will result in significant energy savings. In the advance notice of proposed rulemaking (ANOPR) for distribution transformers, the Department had also conducted analysis on low-voltage, dry-type distribution transformers. 69 FR 45376 (July 29, 2004). However, the Energy Policy Act of 2005 (EPACT 2005) established energy conservation standards for low-voltage, dry-type distribution transformers. (42 U.S.C. 6295(y)) Because of these amendments, DOE removed low-voltage, dry-type distribution transformers—product class 3 (low-voltage, dry-type, single-phase) and product class 4 (low-voltage, dry-type, three-phase)—from this rulemaking. Table I.1 shows the proposed standard levels for the product classes that are still within the scope of this rulemaking.

TABLE I.1.—PROPOSED STANDARD LEVELS FOR DISTRIBUTION TRANSFORMERS

Superclasses—product classes (PC)	Proposed standard levels
Liquid-immersed	Trial Standard Level 2.
Single-phase (PC 1)	
Three-phase (PC 2)	
Medium-voltage, dry-type	Trial Standard Level 2.
Single-phase, 25–45 kV BIL (PC 5)	
Three-phase, 25–45 kV BIL (PC 6)	
Single-phase, 46–95 kV BIL (PC 7)	
Three-phase, 46–95 kV BIL (PC 8)	
Single-phase, ≥96 kV BIL (PC 9)	
Three-phase, ≥96 kV BIL (PC 10)	

Note: PC stands for product class; kV is kilovolt; BIL is basic impulse insulation level.

Tables II.1 and II.2 show the specific efficiency levels for the various kilovolt ampere (kVA) sizes, within each product class, that reflect the Department's proposed standards.

The Department's analyses indicate that the proposed standards, trial standard level 2 (TSL2) for liquid-immersed transformers and TSL2 for medium-voltage, dry-type transformers, would save a significant amount of energy—an estimated 2.4 quads (quadrillion (10^{15}) British thermal units (BTU)) of cumulative energy over 29 years (2010–2038). This amount is roughly equal to the total energy consumption of the Commonwealth of Virginia in 2001. The economic impacts on commercial consumers (*i.e.*, the average life-cycle cost (LCC) savings) are positive.

The national net present value (NPV) of TSL2 is $2.52 billion using a seven-percent discount rate and $9.43 billion using a three-percent discount rate, cumulative from 2010 to 2073 in 2004$. This is the estimated total value of future savings minus the estimated increased equipment costs, discounted to the year 2004. Using a real corporate discount rate of 8.9 percent, the Department estimates the liquid-immersed and medium-voltage, dry-type distribution transformer industry's NPV to be $558 million in 2004$. The impact of the proposed standard on liquid-immersed transformer manufacturers' industry net present value (INPV) is expected to be between a 2.4 percent loss and a 2.0 percent increase (−$12.9 million to $10.7 million). The medium-voltage, dry-type transformer industry is estimated to lose between 10.1 percent and 13.4 percent of its NPV (−$3.3 million to −$4.3 million) as a result of the proposed standard. Based on the Department's interviews with the major manufacturers of distribution transformers, DOE expects minimal plant closings or loss of employment as a result of the proposed standards.

The proposed standards will lead to reductions in greenhouse gases, resulting in cumulative (undiscounted) emission reductions of 167.1 million tons (Mt) of carbon dioxide (CO_2). Additionally, the standards would generate 46.4 thousand tons (kt) of nitrogen oxides (NO_X) emissions reductions or a similar amount of NO_X emissions allowance credits in areas where such emissions are subject to emissions caps. The Department expects the energy savings from the proposed standards to eliminate the need for approximately 11 new 400-megawatt (MW) power plants by 2038.

Therefore, the Department concludes that the benefits (energy savings, commercial consumer LCC savings, national NPV increases, and emissions reductions) to the Nation of the proposed standards outweigh their costs (loss of manufacturer NPV and commercial consumer LCC increases for some users of distribution transformers). The Department concludes that the proposed standards of TSL2 for liquid-immersed and TSL2 for medium-voltage, dry-type transformers are technologically feasible and economically justified. At present, both liquid-immersed and medium-voltage, dry-type transformers are commercially available at the TSL2 standard level.

II. Introduction

A. Consumer Overview

The Department is proposing to set energy-efficiency standard levels for distribution transformers as shown in Tables II.1 and II.2. The proposed standard would apply to liquid-immersed and medium-voltage, dry-type distribution transformers manufactured for sale in the United States, or imported to the United States, on or after January 1, 2010. In preparing these tables, the Department identified some areas where the analytical methods used to develop the efficiency values resulted in discontinuities in the table of efficiencies. Generally, larger transformers will have greater efficiency than smaller transformers, all other factors being equal. Not all efficiency ratings that result from the Department's analysis fit this pattern. The Department invites comment on all the efficiency ratings.

TABLE II.1.—PROPOSED STANDARD LEVEL, TSL2, FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.40	15	98.36
15	98.56	30	98.62
25	98.73	45	98.76
37.5	98.85	75	98.91
50	98.90	112.5	99.01
75	99.04	150	99.08
100	99.10	225	99.17
167	99.21	300	99.23
250	99.26	500	99.32
333	99.31	750	99.24
500	99.38	1000	99.29
667	99.42	1500	99.36
833	99.45	2000	99.40
		2500	99.44

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; 71 FR 24972.

TABLE II.2.—PROPOSED STANDARD LEVEL, TSL2, FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS

Single-phase				Three-phase			
BIL kVA	20–45 kV efficiency (%)	46–95 kV efficiency (%)	≥96 kV efficiency (%)	20–45 kV efficiency (%)	46–95 kV efficiency (%)	≥96 kV efficiency (%)	kVA
15	98.10	97.86		15	97.50	97.19	
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

TABLE II.2.—PROPOSED STANDARD LEVEL, TSL2, FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS—Continued

Single-phase				Three-phase			
BIL kVA	20–45 kV efficiency (%)	46–95 kV efficiency (%)	≥96 kV efficiency (%)	20–45 kV efficiency (%)	46–95 kV efficiency (%)	≥96 kV efficiency (%)	kVA
				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; 71 FR 24972.

B. Authority

Title III of EPCA sets forth a variety of provisions designed to improve energy efficiency. Part B of Title III (42 U.S.C. 6291–6309) provides for the Energy Conservation Program for Consumer Products other than Automobiles. Part C of Title III (42 U.S.C. 6311–6317) establishes a similar program for ''Certain Industrial Equipment,'' and includes distribution transformers, the subject of this rulemaking. The Department publishes today's NOPR pursuant to Part C of Title III, which provides for test procedures, labeling, and energy conservation standards for distribution transformers and certain other products, and authorizes DOE to require information and reports from manufacturers. The distribution transformer test procedure appears in Title 10 Code of Federal Regulations (CFR) Part 431, Subpart K, Appendix A; 71 FR 24972.

EPCA contains criteria for prescribing new or amended energy conservation standards. The Department must prescribe standards only for those distribution transformers for which DOE: (1) Has determined that standards would be technologically feasible and economically justified and would result in significant energy savings, and (2) has prescribed test procedures. (42 U.S.C. 6317(a)) Moreover, as indicated above, the Department analyzed whether today's proposed standards for distribution transformers will achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. (See 42 U.S.C. 6295(o)(2)(A), 6316(a), and 6317(a) and (c)) In addition, DOE will decide whether today's proposed standard is economically justified, after receiving comments on the proposed standard, by determining whether the benefits of the standard exceed its costs. The Department will make this determination by considering, to the greatest extent practicable, the following seven factors which are set forth in 42 U.S.C. 6295(o)(2)(B)(i):

(1) The economic impact of the standard on manufacturers and consumers of the products subject to the standard;
(2) The savings in operating costs throughout the estimated average life of products 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 savings likely to result directly from the imposition of the standard;
(4) Any lessening of the utility or the performance of the products 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 conservation; and
(7) Other factors the Secretary considers relevant.

In developing energy conservation standards for distribution transformers, DOE is also applying certain other provisions of 42 U.S.C. 6295. First, the Department will not prescribe a standard for the product 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 type (or class) of this product with performance characteristics, features, sizes, capacities, and volume that are substantially the same as those generally available in the United States. (See 42 U.S.C. 6295(o)(4))

Second, DOE is applying 42 U.S.C. 6295(o)(2)(B)(iii), which establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that ''the additional cost to the consumer of purchasing a product complying with an energy conservation standard level will be less than three times the value of the energy * * * savings during the first year that the consumer will receive as a result of the standard, as calculated under the applicable test procedure * * *'' The rebuttable-presumption test is an alternative path to establishing economic justification.

Third, in setting standards for a type or class of equipment that has two or more subcategories, DOE will specify a different standard level than that which applies generally to such type or class of equipment for any group of products ''which have the same function or intended use, if * * * products within such group—(A) consume a different kind of energy from that consumed by other covered products within such type (or class); or (B) have a capacity or other performance-related feature which other products within such type (or class) do not have and such feature justifies a higher or lower standard'' than applies or will apply to the other products. (See 42 U.S.C. 6295(q)(1)) In determining whether a performance-related feature justifies such a different standard for a group of products, the Department considers such factors as the utility to the consumer of such a feature and other factors DOE deems appropriate. Any rule prescribing such a standard will include an explanation of the basis on which DOE established such higher or lower level. (See 42 U.S.C. 6295(q)(2))

Federal energy efficiency requirements for equipment covered by 42 U.S.C. 6317 generally supersede State laws or regulations concerning energy conservation testing, labeling, and standards. (42 U.S.C. 6297(a)–(c) and 42 U.S.C. 6316(a)) The Department can, however, grant waivers of preemption for particular State laws or regulations, in accordance with the procedures and other provisions of section 327(d) of the Act. (42 U.S.C. 6297(d) and 42 U.S.C. 6316(a))

C. Background

1. Current Standards

Presently, there are no national energy conservation standards for the liquid-immersed and medium-voltage, dry-type distribution transformers covered by this rulemaking. However, on August 8, 2005, EPACT 2005 established energy conservation standards for low-voltage, dry-type distribution transformers that will take effect on January 1, 2007. (42 U.S.C. 6295(y))

2. History of Standards Rulemaking for Distribution Transformers

On October 22, 1997, the Secretary of Energy published a notice stating that the Department ''has determined, based on the best information currently available, that energy conservation standards for electric distribution transformers are technologically feasible, economically justified and would result in significant energy savings.'' 62 FR 54809.

The Secretary's determination was based, in part, on analyses conducted by the Department's Oak Ridge National Laboratory (ORNL). In July 1996, ORNL published a report entitled *Determination Analysis of Energy Conservation Standards for Distribution Transformers,* ORNL–6847, which assessed options for setting energy conservation standards. That report was based on information from annual sales data, average load data, and surveys of existing and potential transformer efficiencies obtained from several organizations.

In September 1997, ORNL published a second report entitled *Supplement to the ''Determination Analysis'' (ORNL–6847) and NEMA Efficiency Standard for Distribution Transformers,* ORNL–6925. This report assessed the suggested efficiency levels contained in the then-newly published National Electrical Manufacturers Association (NEMA) Standards Publication No. TP 1–1996, *Guide for Determining Energy Efficiency for Distribution Transformers,* along with the efficiency levels previously considered by the Department in the determination study.[1] In its supplemental assessment, ORNL–6925, the ORNL research team used a more accurate analytical model and better transformer market and loading data developed following the publication of ORNL–6847. Downloadable versions of both ORNL reports are available on the DOE Web site at: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html*

As a result of its positive determination, the Department developed the *Framework Document for Distribution Transformer Energy Conservation Standards Rulemaking* in 2000, describing the procedural and analytic approaches the Department anticipated using to evaluate the establishment of energy conservation standards for distribution transformers.[2] This document is also available on the aforementioned DOE Web site. On November 1, 2000, the Department held a public meeting on the Framework Document to discuss the proposed analytical framework. Manufacturers, trade associations, electric utilities, environmental advocates, regulators, and other interested parties attended the Framework Document meeting. The major issues discussed were: Definition of covered transformer products, definition of product classes, possible proprietary (patent) issues regarding amorphous material, ties between efficiency improvements and installation costs, baseline and possible higher efficiency levels, base case trends (i.e., trends absent regulation), transformer costs versus transformer prices, appropriate LCC subgroups, LCC methods (e.g., total owning cost (TOC)), loading levels, utility impact analysis vis-a-vis deregulation, scope of environmental assessment, and harmonization of standards with other countries.

Stakeholder comments submitted during the Framework Document comment period elaborated on the issues raised at the meeting and also addressed the following issues: Options for the screening analysis, approaches for the engineering analysis, discount rates, electricity prices, the number and basis for the efficiency levels to be analyzed, the national energy savings (NES) and NPV analyses, the analysis of the effects of a potential standard on employment, the manufacturer impact analysis (MIA), and the timing of the analyses.

As part of the information gathering and sharing process, the Department met with manufacturers of liquid-immersed and dry-type distribution transformers during the first quarter of 2002. The Department met with companies that produced all types of distribution transformers, ranging from small to large manufacturers, and including both NEMA and non-NEMA members. The Department had three objectives for these meetings: (1) Solicit feedback on the methodology and findings presented in the draft engineering analysis update report that the Department posted on its Web site December 17, 2001, (2) obtain information and comments on production costs and manufacturing processes presented in the draft engineering analysis update report, and (3) provide to manufacturers an opportunity, early in the rulemaking process, to express specific concerns to the Department.

Seeking early and frequent consultation with stakeholders, the Department posted draft reports on its website as it prepared for the publication of the ANOPR. The reports included draft screening analysis findings, and draft engineering analysis and LCC analysis reports on 50 kVA single-phase, liquid-immersed, pad-mounted transformers and 300 kVA three-phase, medium-voltage, dry-type transformers. The Department also held a live, online Web cast on October 17, 2002, giving an overview of the LCC analysis and a tutorial on the use of the LCC spreadsheet. The Department received comments from stakeholders on all the draft publications, which helped improve the quality of the analysis included in the ANOPR published on July 29, 2004. 69 FR 45376.

In the ANOPR, the Department invited stakeholders to comment on the following key issues: Definition and coverage, product classes, engineering analysis inputs, design option combinations, the 0.75 scaling rule, modeling of transformer load profiles, distribution chain markups, discount rate selection and use, baseline determination through purchase evaluation formulae, electricity prices, load growth over time, life-cycle cost subgroups, and utility deregulation impacts.

In preparation for the September 28, 2004, ANOPR public meeting, the Department held a Web cast on August 10, 2004, to acquaint stakeholders with the analytical tools (spreadsheets) and other material published the previous month. During the ANOPR comment period, which ended on November 9, 2004, stakeholders submitted comments on the 13 issues listed above, as well as on other issues. These comments are discussed in section IV of this NOPR.

On August 5, 2005, the Department posted on its Web site several draft NOPR analyses for early public review, including draft technical support document (TSD) chapters on the engineering analysis, the energy use and end-use load characterization, the markups for equipment price determination, the LCC and payback period analyses, the shipments analysis, the national impact analysis, and the MIA. The Department also posted draft NOPR spreadsheets for the engineering

[1] **Note:** NEMA later updated TP 1 in 2002 (NEMA TP 1–2002), in which it increased some of the efficiency levels. The latest version of TP 1 is available at the NEMA Web site: *http://www.nema.org/stds/tp1.cfm#download.*

[2] The Department published a notice of availability of the Framework Document in the **Federal Register**. 65 FR 59761 (October 6, 2000). The Framework Document itself is available on the DOE Web site: *http://www.eere.energy.gov/buildings/appliance_standards/commercial/pdfs/trans_framework.pdf.*

analysis, LCC analysis, national impact analysis, and MIA on its Web site.

On August 8, 2005, President Bush signed into law EPACT 2005, Public Law 109–58. Section 135(c)(4) of this Act establishes minimum efficiency levels for low-voltage, dry-type transformers manufactured, or imported into the U.S., on or after January 1, 2007. (42 U.S.C. 6295(y)) The levels are those appearing in Table 4–2 of NEMA TP 1–2002, *Guide for Determining Energy Efficiency for Distribution Transformers.* The Department incorporated this standard along with efficiency standards for several other products and equipment in a **Federal Register** Notice. 70 FR 60407 (October 18, 2005). Because EPACT 2005 established standards for low-voltage, dry-type distribution transformers, the Department is no longer considering standards for the single- and three-phase, low-voltage dry-type distribution transformers in this rulemaking.

In conjunction with this NOPR, the Department also published on its website the complete TSD and several spreadsheets. The TSD contains technical documentation of each analysis conducted under this rulemaking, providing specific information on the methodology and results. The spreadsheets, discussed in the relevant TSD chapters, represent the analytical tools and results that support today's proposed rule. The engineering analysis spreadsheets represent the Department's design database, providing the cost-efficiency relationships for the 10 specific distribution transformer units analyzed—five liquid-immersed and five medium-voltage, dry-type units. The LCC spreadsheet calculates the LCC and payback periods at six standard levels for these representative units. The national impact analysis spreadsheet tool calculates impacts of efficiency standards on distribution transformer shipments, as well as the NES and NPV of the standard levels considered. The MIA spreadsheet evaluates the financial impact of standards on distribution transformer manufacturers. All of these spreadsheet tools are posted on the Department's Web site, along with the complete NOPR TSD, at *http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers_draft_analysis_nopr.html.*

3. Process Improvement

The ''Process Rule,'' *Procedures, Interpretations and Policies for Consideration of New or Revised Energy Conservation Standards for Consumer Products,* Title 10 CFR Part 430, Subpart C, Appendix A, applies to the development of energy-efficiency standards for consumer products. While distribution transformers are considered a commercial product, the Department decided to apply some of the provisions of the ''Process Rule'' to this rulemaking.

In today's notice, the Department describes the framework and methodologies for developing the proposed standards. The framework and methodologies reflect improvements made, and steps taken, in accordance with the Process Rule, including DOE's use of economic models and analytical tools. Since the rulemaking process is dynamic, if timely new data, models, or tools that enhance the development of standards become available, the Department will incorporate them into the rulemaking.

III. General Discussion

A. Test Procedures

Section 7(b) of the Process Rule requires that the Department propose necessary modifications to the test procedure for a product before issuing a NOPR concerning efficiency standards for that product. Section 7(c) of the Process Rule states that DOE will issue a final, modified test procedure prior to issuing a proposed rule for energy conservation standards. The test procedure for distribution transformers was published as a final rule on April 27, 2006. 71 FR 24972.

B. Technological Feasibility

1. General

The Department considers design options technologically feasible if they are in use by the respective industry or if research has progressed to the development of a working prototype. The Process Rule sets forth a definition of technological feasibility as follows: ''Technologies incorporated in commercially available products or in working prototypes will be considered technologically feasible.'' 10 CFR Part 430, Subpart C, Appendix A, section 4(a)(4)(i).

In each standards rulemaking, the Department conducts a screening analysis, which is based on information gathered regarding existing technology options and prototype designs. In consultation with manufacturers, design engineers, and other stakeholders, the Department develops a list of design options for consideration in the rulemaking. Once the Department has determined that a particular design option is technologically feasible, it then further evaluates each design option in light of the other three criteria in the Process Rule. 10 CFR Part 430, Subpart C, Appendix A, section 4(a)(3) and (4). The three additional criteria are: (a) Practicability to manufacture, install, or service, (b) adverse impacts on product utility or availability, or (c) health or safety concerns that cannot be resolved. 10 CFR Part 430, Subpart C, Appendix A, section 4(a). All design options that pass these screening criteria are candidates for further assessment.

As discussed in the ANOPR for this rulemaking, the Department is not considering the following design options because they do not meet one or more of the screening criteria: Silver as a conductor material, high-temperature superconductors, amorphous core material in stacked core configuration, carbon composite materials for heat removal, high-temperature insulating material, and solid-state (power electronics) technology. 69 FR 45387. For the NOPR, there were no changes to the list of technology options screened out of the ANOPR analysis. Discussion of the application of the screening analysis criteria to the design options appears in Chapter 4 of the TSD.

The Department believes that all of the efficiency levels evaluated in today's notice are technologically feasible. The technologies incorporated in the transformer design database have all been used (or are being used) in commercially available products or working prototypes. The designs all incorporate core steel and conductor types that are commercially available in today's transformer materials supply market. Any one manufacturer may not be using all the materials considered by the Department for a given model analyzed, but these materials could be purchased from multiple suppliers today if design changes warranted it.

In addition, to prepare transformer designs for evaluation, DOE used transformer design software that is also used by manufacturers in the U.S. and abroad. The Department evaluated the transformer design software by comparing the software's designs against six transformers it purchased, tested, and disassembled. For these units, the software accurately predicted the performance and manufacturer selling prices when using the same material cost, labor cost, and manufacturer markup assumptions that were used in the engineering analysis for the NOPR (see TSD Chapter 5, section 5.7).

For liquid-immersed distribution transformers, the designs prepared by the software were all wound-core designs. The least efficient design used M6 core steel and the most efficient used amorphous material. All designs contained in the Department's design database could be built today. For medium-voltage, dry-type transformers, DOE used commercially available core steels, ranging from M6 through domain-refined 9-mil (0.009 inch) high permeability, grain-oriented steel (H–O DR). Core-construction techniques included butt-lap, mitered, and cruciform construction. The conductors and insulation types used were all conventional, and are commercially available in distribution transformers today. Thus, the Department believes that all the efficiency levels discussed in today's proposed rule are technologically feasible.

2. Maximum Technologically Feasible Levels

In developing today's proposed standards, the Department followed the provisions of 42 U.S.C. 6295(p)(2), which states that, when the Department proposes to adopt, or to decline to adopt, an amended or new standard for each type (or class) of covered product, ''the Secretary shall determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible.'' The Department determined the maximum technologically feasible (''max-tech'') efficiency level in the engineering analysis (see TSD Chapter 5) using the most efficient materials not screened out and applying design parameters that drove the transformer design software to create designs at the highest efficiencies achievable. The Department then used these highest-efficiency designs to establish the max-tech level for the LCC analysis (see TSD Chapter 8). In the national impact analysis (see TSD Chapter 10), the Department then scaled these max-tech efficiencies to the other kVA ratings within a given design line, establishing max-tech efficiencies at all the distribution transformer kVA ratings. Tables III.1 and III.2 provide the complete list of max-tech efficiency levels considered for all kVA ratings within each product class.

TABLE III.1.—MAX-TECH LEVELS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	99.32	15	99.31
15	99.39	30	99.42
25	99.46	45	99.47
37.5	99.51	75	99.54
50	99.59	112.5	99.58
75	99.59	150	99.61
100	99.62	225	99.65
167	99.66	300	99.67
250	99.70	500	99.71
333	99.72	750	99.66
500	99.75	1000	99.68
667	99.77	1500	99.71
833	99.78	2000	99.73
		2500	99.74

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; 71 FR 24972.

TABLE III.2.—MAX.-TECH LEVELS FOR MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS

Single-phase				Three-phase			
BIL kVA	20–45 kV efficiency (%)	46–95 kV efficiency (%)	≥96 kV (%)	kVA	20–45 kV efficiency (%)	46–95 kV efficiency (%)	≥96 kV efficiency (%)
15	99.05	98.54		15	98.75	98.08	
25	99.17	98.71		30	98.95	98.38	
37.5	99.25	98.84		45	99.05	98.54	
50	99.30	98.92		75	99.17	98.71	
75	99.37	99.02	99.22	112.5	99.25	98.84	
100	99.41	99.09	99.28	150	99.30	98.92	
167	99.48	99.20	99.36	225	99.37	99.02	99.22
250	99.42	99.42	99.42	300	99.41	99.09	99.28
333	99.46	99.46	99.46	500	99.48	99.20	99.36
500	99.51	99.51	99.52	750	99.42	99.42	99.42
667	99.54	99.54	99.55	1000	99.46	99.46	99.46
833	99.57	99.57	99.57	1500	99.51	99.51	99.52
				2000	99.54	99.54	99.55
				2500	99.57	99.57	99.57

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; 71 FR 24972.

C. Energy Savings

One of the criteria that govern the Department's adoption of standards for distribution transformers is that the standard must result in ''significant'' energy savings. (42 U.S.C. 6317(a)) While the term ''significant'' is not defined by EPCA, a U.S. Court of Appeals, in *Natural Resources Defense Council* v. *Herrington*, 768 F.2d 1355, 1373 (D.C. Cir. 1985), indicated that Congress intended ''significant'' energy savings in a similar context in Section 325 of the Act to be savings that were not ''genuinely trivial.'' The energy savings for all of the trial standard levels considered in this rulemaking are nontrivial, and therefore the Department considers them ''significant'' as required by 42 U.S.C. 6317.

D. Economic Justification

As noted earlier, EPCA provides seven factors to be evaluated in determining whether an energy conservation standard for distribution transformers is economically justified. The following discusses how the Department has addressed each of those seven factors thus far in this rulemaking. (42 U.S.C. 6295(o)(2)(B)(i))

1. Economic Impact on Manufacturers and Commercial Consumers

The Process Rule established procedures, interpretations, and policies to guide the Department in the consideration of new or revised appliance efficiency standards. The provisions of the rule have direct bearing on the implementation of the MIA. First, the Department used an annual-cash-flow approach in determining the quantitative impacts of a new or amended standard on manufacturers. This included both a short-term assessment based on the cost and capital requirements during the period between the announcement of a regulation and the time when the regulation comes into effect, and a long-term assessment. Impacts analyzed include industry NPV, cash flows by year, changes in revenue and income, and other measures of impact, as appropriate. Second, the Department analyzed and reported the impacts on different types of manufacturers, with particular attention to impacts on small manufacturers. Third, the Department considered the impact of standards on domestic manufacturer employment, manufacturing capacity, plant closures, and loss of capital investment. Finally, the Department took into account cumulative impacts of different DOE regulations on manufacturers.

For commercial consumers, measures of economic impact are the changes in installed (first) cost and annual operating costs. To assess the impact on first cost, the Department considered the percent increase in the consumer equipment cost before installation. To assess the impact on life-cycle costs, which include both consumer equipment costs and annual operating costs, the Department conducted an LCC analysis of the equipment at each candidate standard level (CSL) (*see* below).

2. Life-Cycle Costs

The LCC is the sum of the purchase price, including the installation, and the operating expense—including operating energy consumption, maintenance, and repair expenditures—discounted over the lifetime of the equipment. To determine the purchase price including installation, DOE estimated the markups that are added to the manufacturer selling price by distributors and contractors, and estimated installation costs from an analysis of transformer installation cost estimates for a wide range of weights and sizes. The Department assumed that maintenance and repair costs are not dependent on transformer efficiency. In estimating operating energy costs, DOE used the full range of commercial consumer marginal energy prices, which are the energy prices that correspond to incremental changes in energy use.

For each distribution transformer representative unit, the Department calculated both LCC and LCC savings from a base-case scenario for six candidate standard efficiency levels. The six candidate standard levels were chosen to correspond to the following:

- NEMA TP 1–2002;
- ⅓ of efficiency difference between TP 1 and minimum LCC;
- ⅔ of efficiency difference between TP 1 and minimum LCC;
- Minimum LCC;
- Maximum energy savings with no change in LCC; and
- Maximum technologically feasible.

In order to calculate the appropriate efficiency levels for kVA ratings that were not analyzed (*i.e.*, all the kVA ratings other than the ten representative units), the Department applied a scaling rule to extrapolate the findings on the ten representative units to these other ratings. For information on the scaling rule, *see* section IV.B.1 and TSD Chapter 5, section 5.2.2.

The Department presents the calculated LCC savings as a distribution, with a mean value and range. The Department used a distribution of consumer real discount rates for the calculations, with mean values ranging from 3.3 to 7.5 percent, specific to the cost of capital faced by purchasers of the representative units. Chapter 8 of the TSD contains the details of the LCC calculations. The LCC is one of the factors DOE considers in determining the economic justification for a new or amended standard. (*See* 42 U.S.C. 6295(o)(2)(B)(i)(II))

3. Energy Savings

While significant conservation of energy is a separate statutory requirement for imposing an energy conservation standard, in determining the economic justification of a standard, the Department considers the total projected energy savings that are expected to result directly from the standard. (See 42 U.S.C. 6295(o)(2)(B)(i)(III)) The Department used the NES spreadsheet results in its consideration of total projected savings. The savings figures are discussed in section V.A.3 of this notice.

4. Lessening of Utility or Performance of Equipment

In establishing classes of products, and in evaluating design options and the impact of potential standard levels, the Department avoided having new standards for distribution transformers that lessen the utility or performance of the equipment under consideration in this rulemaking. None of the proposed trial standard levels reduces the utility or performance of distribution transformers. (See 42 U.S.C. 6295(o)(2)(B)(i)(IV)) The Department's engineering options do not change the utility and performance of distribution transformers. The impact of any increase in transformer weight associated with efficiency improvements is captured by the economic analysis. Specifically, installation costs for pole-mounted transformers include estimates of stronger pole and pole change-out costs that may be incurred with heavier, more efficient transformers.

5. Impact of Any Lessening of Competition

The Department considers any lessening of competition that is likely to result from standards. Accordingly, DOE has written to the Attorney General to request that the Attorney General transmit to the Secretary, not later than 60 days after the publication of this proposed rule, a written determination of the impact, if any, of any lessening of competition likely to result from the proposed standard, together with an analysis of the nature and extent of such impact. (See 42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii))

6. Need of the Nation To Conserve Energy

The non-monetary benefits of the proposed standard are likely to be reflected in improvements to the security and reduced reliability costs of the Nation's energy system—namely, reductions in the overall demand for energy will result in reduced costs for maintaining reliability of the Nation's electricity system. The Department conducts a utility impact analysis to show the reduction in installed generation capacity requirements. Reduced power demand (including peak power demand) generally reduces the costs of maintaining the security and reliability of the energy system.

The Department has determined that today's proposed standard should result in reductions in greenhouse gas emissions. The Department quantified a range of primary energy conversion factors and estimated the emissions reductions associated with the generation displaced by energy-efficiency standards. The environmental effects from each trial standard level for this equipment are reported in the TSD environmental assessment. (See 42 U.S.C. 6295(o)(2)(B)(i)(VI))

7. Other Factors

The Secretary of Energy, in determining whether a standard is economically justified, considers any other factors that the Secretary deems to be relevant. (See 42 U.S.C. 6295(o)(2)(B)(i)(VII)) For today's proposed standard, the Secretary took into consideration a factor relating to several comments received at the ANOPR public meeting, during the comment period following the meeting, and in the MIA interviews. Stakeholders expressed concern about the increasing cost of raw materials for building transformers, the volatility of material prices, and the cumulative effect of material price increases on the transformer industry (see section IV.B.2, Engineering Analysis Inputs). The Department conducted supplementary engineering and LCC analyses using first-quarter 2005 material prices and considered the impacts on LCC savings and payback periods when evaluating the appropriate standard levels for liquid-immersed and medium-voltage, dry-type distribution transformers. The results of the engineering and LCC analyses for the first-quarter 2005 material pricing analysis are in TSD Appendix 5C.

IV. Methodology and Discussion of Comments

A. Market and Technology Assessment

1. Product Classes

In general, when evaluating and establishing energy-efficiency standards, the Department divides covered products into classes by: (a) The type of energy used, or (b) capacity, or other performance-related features, such as those that affect both consumer utility and efficiency. Different energy-efficiency standards may apply to different product classes. As discussed in the ANOPR, the Department received some guidance from stakeholders on establishing appropriate product classes for the population of distribution transformers. 69 FR 45385. Originally, the Department created 10 product classes, dividing up the population of distribution transformers by:

- Type of transformer insulation—liquid-immersed or dry-type;
- Number of phases—single or three;
- Voltage class—low or medium (for dry-type units only); and
- Basic impulse insulation level (for medium-voltage, dry-type units only).

EPACT 2005 includes provisions establishing energy conservation standards for two of the Department's product classes (PC3, low-voltage, single-phase, dry-type and PC4, low-voltage, three-phase, dry-type). (42 U.S.C. 6295(y)) With standards thereby established for low-voltage, dry-type distribution transformers, the Department is no longer considering these two product classes for standards. Table IV.1 presents the eight product classes that remain within the scope of this rulemaking.

TABLE IV.1.—DISTRIBUTION TRANSFORMER PRODUCT CLASSES FOR THE NOPR

PC No.*	Insulation	Voltage	Phase	BIL rating	kVA range
PC1	Liquid-Immersed		Single		10–833 kVA.
PC2	Liquid-Immersed		Three		15–2500 kVA.
PC5	Dry-Type	Medium	Single	20–45 kV BIL	15–833 kVA.
PC6	Dry-Type	Medium	Three	20–45 kV BIL	15–2500 kVA.
PC7	Dry-Type	Medium	Single	46–95 kV BIL	15–833 kVA.
PC8	Dry-Type	Medium	Three	46–95 kV BIL	15–2500 kVA.
PC9	Dry-Type	Medium	Single	≥96 kV BIL	75–833 kVA.
PC10	Dry-Type	Medium	Three	≥96 kV BIL	225–2500 kVA.

***Note:** Although the PC3 and PC4 product classes are no longer included in this rulemaking, for consistency with prior material published under this rulemaking, the Department has not renumbered the liquid-immersed and medium-voltage, dry-type product classes that remain.

DOE received no comments that requested modifications to the Department's product classes as proposed in the ANOPR. However, Howard Industries commented that it supported the independent categorization of liquid-immersed and dry-type transformers. It pointed out that the applications and type of customers for these two types of transformers can vary widely. (Howard, No. 70 at p. 2) The Department agrees with this comment and continues to treat liquid-immersed and dry-type transformers separately in its analysis.

Concerning the use of three basic impulse insulation level (BIL) groupings for medium-voltage, dry-type transformers, Federal Pacific Transformer (FPT) noted that BIL levels do affect cost and efficiency, and agreed that DOE should conduct its analysis by BIL grouping. It commented that the efficiency levels should be modeled according to the BIL levels as much as possible. (FPT, No. 64 at p. 3) NEMA commented that it was willing to change the BIL groupings in TP 1–2002 from two to three, so TP 1 would have the same BIL groupings for medium-voltage, dry-type transformers as the Department's proposal. (NEMA, No. 60 at p. 2) The Alliance to Save Energy (ASE) commented that the Department's refinement of BIL classifications over TP 1 is justified and should result in more appropriate efficiency levels. (ASE, No. 52 at p. 2 and No. 75 at p. 2) Finally, the Oregon Department of Energy (ODOE) commented that it supports the refinements that created three BIL groupings for these transformers. (ODOE, No. 66 at p. 2) The Department did not receive any comments critical of the three BIL groupings for medium-voltage, dry-type transformers, and therefore continues to use these same BIL groupings in today's proposed rule.

Howard Industries and ASE commented on whether DOE should regulate the efficiency of liquid-immersed transformers. Howard commented that, for liquid-immersed transformers—especially for the utility, municipal, and co-operative segments—energy-efficiency standards should be voluntary because these transformer customers are already considering life-cycle costs in their purchasing decisions. (Howard, No. 70 at p. 4) Howard commented that it feels a voluntary program would be better for the whole utility market than a mandatory standard. Howard believes a mandatory program would contribute to standardization of liquid-immersed transformer designs, and encourage manufacturers to move to countries with lower labor costs. Howard suggested that the ballast and electric motor industries are two examples of products where mandatory standards were implemented and domestic manufacturing declined. (Howard, No. 70 at p. 2) ASE agreed with the Department's decision that liquid-immersed transformers fall within the scope of the standard. (ASE, No. 75 at p. 2) Under 42 U.S.C. 6317, the Department is charged in this rulemaking with determining whether standards for distribution transformers are technologically feasible and economically justified and would result in significant energy savings. Based on the Department's analysis and information available to date, standards for liquid-immersed transformers appear to be technologically feasible and economically justified, and would result in significant energy savings. The Department considered a voluntary program, NEMA TP–1 in its Determination Analysis, but concluded that the ''efficiency levels would capture the most cost effective energy savings but may not capture substantial energy savings that appear to be economically justified and technologically feasible.'' 62 FR 54816. In addition, the Department considered the impact of voluntary programs in its regulatory impact analysis (see the report in the TSD ''Regulatory Impact Analysis for Electrical Distribution Transformers''), and found that a voluntary program would not result in standards that achieve the maximum efficiency level that is technologically feasible and economically justified. Thus, in accordance with 42 U.S.C. 6317, the Department intends to continue to consider liquid-immersed distribution transformers for energy efficiency standards. To gain a better understanding of the concern raised by Howard Industries about minimum efficiency standards leading to design standardization, the Department requests that other stakeholders comment on this issue.

2. Definition of a Distribution Transformer

The Department received several comments from stakeholders on the definition of a distribution transformer. The Department has established the definition (and scope of this rulemaking) in its final rule on the test procedure for distribution transformers. 10 CFR Part 431, Subpart K; 71 FR 24972.

EPCA directed DOE to develop standards for those ''distribution transformers'' for which energy conservation standards would be technologically feasible and economically justified, and would result in significant energy savings, but did not specify a definition for a distribution transformer. (42 U.S.C. 6317(a)) Thus, the Department began developing a definition in the determination analysis, and refined that definition through the test procedure rulemaking and this rulemaking. This process was obviated to a substantial extent by the enactment of EPACT 2005, which amended EPCA to, among other things, include a definition of a distribution transformer. (42 U.S.C. 6291(35)) The existing statutory definition establishes the scope of coverage for this rulemaking.

Before the passage of EPACT 2005, stakeholders had submitted comments on the definition of a distribution transformer presented in the ANOPR. These comments are summarized here with discussion on whether or not the new EPCA definition of a distribution transformer, promulgated in EPACT 2005, addresses the issues raised by the stakeholders. For more detail on the definition of a distribution transformer, please see the test procedure final rule notice. 71 FR 24972.

PEMCO and Southern Company commented on exclusions for dimensionally or physically constrained transformers. PEMCO noted that an exclusion for replacement or retrofit transformers is needed because they must have exactly the same physical dimensions as the ones they are replacing. (PEMCO, No. 57 at p. 1) Southern Company agreed, noting that in retrofit installations, size and weight are a factor. Southern commented that, as transformer efficiency increases, the units become larger and obstructions and required minimum clearances are more difficult to achieve. Southern noted that this is true for both liquid-immersed, pad-mounted units and dry-type transformers installed in buildings. It concluded that the increased size is likely to cause both delivery and installation problems in many locations. (Southern, No. 71 at p. 2) At the ANOPR public meeting, Ameren commented that the Department should consider the impact of different size/configurations resulting from increased efficiency on the speed and ease of emergency replacement transformers. (Public Meeting Transcript, No. 56.12 at pp. 255–256) The Department accounted for generally applicable dimensional and physical constraints on transformer installation through the inclusion of size- and weight-dependent installation costs in its LCC model. These costs include potential pole change-out costs for large overhead transformers, and the size- and weight-dependent labor and equipment costs associated with installing larger transformers. The costs estimated by the Department do not include the costs of rehabilitating confined spaces that may have to be modified for the installation of larger transformers. This issue is similar to the situation that arises when utilities and contractors need to increase transformer size due to load growth. One method of modeling such costs would be to include a space-occupancy cost to the cost of transformer operation. The Department invites comment on whether space-occupancy costs should be included in transformer cost estimates and which methods are appropriate for estimating such costs.

Howard and FPT expressed concern about distribution transformers designed for use in specific environments. Howard recommended that underground and subway-style transformers be excluded from the standards. Howard noted that these transformers are often being retrofitted into existing concrete vaults and, in most cases, the whole concrete structure would need to be replaced if DOE mandated a more efficient unit. (Howard, No. 70 at p. 3) FPT recommended that the Department consider exempting mining transformers designed for installation inside equipment with severe space limitations, due to their radically different loss characteristics. FPT noted that efficiency standards could cause problems in applications where these transformers would not fit. (Public Meeting Transcript, No. 56.12 at pp. 54–56; FPT, No. 64 at p. 2) ODOE commented that it had no objection to the Department excluding specialty transformers for the mining industry, provided that the exclusion can be written so as not to inadvertently create a loophole for other end uses. (ODOE, No. 66 at p. 2) As amended, EPCA does not exclude these types of dimensionally constrained transformers from its definition of distribution transformer. Furthermore, although 42 U.S.C. 6291(35)(B)(iii) authorizes DOE to exclude additional types of distribution transformers, DOE does not have a sufficient basis for excluding dimensionally constrained transformers under this provision. While these transformers apparently are designed for special applications, in line with 42 U.S.C. 6291(35)(B)(iii)(I), DOE lacks specific information on the other two criteria, namely, whether these transformers would be likely to be used in general purpose applications, and whether significant energy savings would result from applying standards to them. Stakeholders have submitted neither data on the energy savings potential of standards for these transformers, nor information as to the likelihood they could be used in general purpose applications. Therefore, the Department is not proposing to exclude any of the transformers discussed in this paragraph under section 321(35)(B)(iii) of EPCA. (42 U.S.C. 6291(35)(B)(iii))

On the issue of harmonic mitigating and harmonic tolerating transformers, most of the comments proposed eliminating the exemption for these types of distribution transformers. At the ANOPR public meeting, both the American Council for an Energy Efficient Economy (ACEEE) and NEMA commented that they supported the elimination of the exemption for harmonic mitigating and harmonic tolerating (or K-rated) transformers. (Public Meeting Transcript, No. 56.12 at p. 27 and p. 35) In written comments, ACEEE, Harmonics Limited, NEMA, and ODOE all recommended eliminating the exemption for harmonic mitigating and harmonic tolerating (or K-rated) transformers. (ACEEE, No. 50 at p. 2 and No. 76 at p. 4; Harmonics Limited, No. 59 at p. 1; NEMA, No. 48 at p. 3 and No. 60 at p. 2; ODOE, No. 66 at p. 2) PEMCO commented that it agrees with including K-factor transformers as covered equipment to stop the current practice of using that exemption to avoid efficiency requirements. (PEMCO, No. 57 at p. 2)

EMS International Consulting (EMSIC) provided a different viewpoint on harmonic tolerating transformers (or K-factor designs); it commented that it believes K-factor and harmonic mitigating transformers (up to a certain level of K-factor) should be subject to standards. (EMSIC, No. 73 at p. 3) FPT went further, proposing a more detailed treatment of K-factor designs. FPT recognizes that some parties are specifying K-factor transformers as a means of getting around State standards requiring TP 1, and that this would probably happen more if DOE exempts K-factor transformers broadly. Therefore, FPT recommended that: (1) Transformers rated up to 300 kVA and having a K-factor of K–13 or less be required to comply with the efficiency standards, and (2) transformers above 300 kVA and having a K-factor of K–4 or less be required to comply with the efficiency standards. (FPT, No. 64 at p. 2)

The definition of a distribution transformer in EPACT 2005 does not contain an explicit exemption for harmonic mitigating or harmonic tolerating (K-rated) transformers. Furthermore, DOE does not have a sufficient basis for excluding them under 42 U.S.C. 6291(35)(B)(iii). While these transformers apparently are designed for special applications, in line with 42 U.S.C. 6291(35)(B)(iii)(I), DOE lacks specific information on the other two criteria, namely, whether these transformers would be likely to be used in general purpose applications, and whether significant energy savings would result from applying standards to them. Therefore, the Department is not proposing to exclude any of the transformers discussed in this paragraph under section 321(35)(B)(iii) of EPCA. 42 U.S.C. 6291(35)(B)(iii).

On the issue of non-ventilated transformers, the Department received a comment from NEMA indicating that it agrees with the Department's exclusion of non-ventilated transformers because of the inherent core losses in such designs. (NEMA, No. 60 at p. 1) This exclusion is now required by EPCA, because EPACT 2005 included an exemption for sealed and non-ventilated transformers.

On the issue of refurbished transformers, the Department received comments representing different viewpoints. Georgia Power commented that DOE's documentation is not clear on the reuse of transformers that have been removed from service for refurbishment. It indicated that it saves approximately 11.5 percent of its total transformer budget by refurbishing and reusing transformers. Georgia Power concluded that, if the Department requires these units to be regulated, it will have a significant financial impact on utilities. (Georgia Power, No. 78 at p. 3)

Manufacturers, on the other hand, appear to be concerned that the increased cost of new, standards-compliant transformers would cause some customers to either purchase rebuilt transformers or refurbish existing ones they own. ERMCO is concerned that if these products are not subject to standards, it may be possible for an end user to avoid the standard by always rewinding failed units. ERMCO stated that there are several independent and utility-owned repair shops that refurbish: Some make minor repairs, others rewind coils. (ERMCO, No. 58 at p. 2) Howard commented that when the final rule is established, it is absolutely essential that it apply to new transformers, used transformers, and repaired transformers. (Howard, No. 70 at p. 3) HVOLT recommended that the Department require any rebuilt transformer that has a winding replaced to meet the new standard, stating that this is necessary to remove a major loophole and would ultimately result in improved energy efficiency for the country. (HVOLT, No. 65 at p. 3 and Public Meeting Transcript, No. 56.12 at p. 59) EMSIC commented that it believes that all refurbished (''repaired'') units should be subject to the new standards to close a potential loophole. (EMSIC, No. 73 at p. 3) ODOE agreed that re-wound transformers should be required to meet the new standards. ODOE also commented that some organizations in the Pacific Northwest have been involved in promotion of high-quality rewinding practices. Through these programs, it has become evident that high-quality work in this area can produce a product that meets the same performance specifications as a new product, while poor-quality work can seriously degrade performance. (ODOE, No. 66 at p. 2)

EPACT 2005's definition of a distribution transformer does not mention refurbished or repaired transformers, and therefore no guidance on treatment of these transformers is provided by the statute. Furthermore, the Department's regulatory authority with respect to refurbished equipment is not clearly delineated. EPCA, as amended by EPACT 2005, seems to require that only newly manufactured distribution transformers meet Federal efficiency requirements. (42 U.S.C. 6302, 6316(a) and 6317(a)(1)) Thus, DOE believes it lacks authority to require used and repaired transformers to comply with energy conservation standards. The same may be true for rebuilt transformers, although DOE's authority is an issue. Generally, EPCA provides that products, when ''manufactured,'' are subject to efficiency standards. (42 U.S.C. 6302 and 6316) It is arguable, but by no means clear, that rebuilt transformers (i.e., those with one or more coils re-wound) could be considered to be ''manufactured'' again when they are rebuilt, and therefore be classified as new distribution transformers subject to standards. If, however, rebuilt products cannot be classified as newly manufactured, DOE would be subject to the same lack of authority to regulate them as applies to other used and repaired products. In addition, the Department does not have authority to regulate the efficiency of distribution transformers re-wound by their owners (i.e., ownership of the transformer is not transferred or sold to another party), despite the suggestion of some commenters that DOE do so. EPCA provides authority to regulate only products that are sold, imported, or otherwise placed in commerce. (42 U.S.C. 6291, 6311, and 6317(f)(1))

Throughout the history of its appliance and commercial equipment energy conservation standards program, DOE has not sought to regulate used units that have been reconditioned or rebuilt, or that have undergone major repairs. For transformers, regulating this part of the market, including the enforcement of efficiency requirements, would be a complex and burdensome task. By and large, the Department believes EPCA indicates a Congressional intent that DOE focus on the market for new products, and believes this is where the most energy savings can be achieved. For distribution transformers in particular, the Department understands that, at present, rebuilt transformers are only a small part of the market.

For all of these reasons, the Department is proposing not to include energy conservation standards for used, repaired, and rebuilt distribution transformers in this rulemaking. Nevertheless, the Department recognizes the concerns raised by commenters about possible substitution of rebuilt transformers for new transformers. If conditions change—for example, if rebuilt transformers become a larger segment of the transformer market—DOE will reconsider its decision not to subject them to energy conservation requirements. The Department invites comment on this decision.

On the issue of excluding special impedance transformers, the Department received one comment from Howard. In response to the ANOPR table of normal impedance ranges, Howard provided a slightly revised table of ''normal'' impedance ranges that it believes are more in line with the American National Standards Institute (ANSI) standards with which most utility systems comply. (Howard, No. 70 at p. 3) Howard's table contains slightly narrower bands of ''normal'' impedance ranges, which would result in fewer transformers being subject to standards and more transformers being classified as exempt. The Department is concerned that some transformers designed for electricity distribution could be manufactured with impedances outside normal ranges so that they would not be subject to otherwise applicable efficiency standards. Such transformers could have a competitive advantage over standards-compliant distribution transformers. If this occurred, it would subvert the standards. The Department also notes that, in NEMA's revised test procedure document, NEMA TP 2–2005, the tables of normal impedance ranges for both liquid-immersed and dry-type transformers are exactly the same as those published by the Department. Thus, in the test procedure final rule notice, the Department retained its tables of ''normal'' impedance ranges. 71 FR 24972.

B. Engineering Analysis

The purpose of the engineering analysis was to evaluate a range of transformer efficiency levels and associated manufacturing selling prices. The engineering analysis considered technologies and design option combinations that were not screened out by the four criteria in the screening analysis. In the LCC analysis, the Department used the manufacturer selling price-efficiency relationships developed in the engineering analysis when it considered the consumer costs of moving to higher efficiency levels.

For the distribution transformers engineering analysis, the Department learned that manufacturers in both the liquid-immersed and medium-voltage, dry-type sectors commonly use software to design a distribution transformer to fill a customer's order. This software-design approach follows from the actual dynamics in the transformer market, where customers often specify certain performance characteristics and requirements. Manufacturers then compete for the contract based on the customized designs they generate using their software, which takes into account the customer's requirements and current material costs.

Consistent with this approach, the Department used transformer design software to create a database of distribution transformer designs spanning a range of efficiencies, while tracking all the modifications to the core, coil, labor, and other cost components. The software creates transformer designs and cost and performance characteristics associated with those designs that, when compiled, characterize the relationship between cost and efficiency. The Department selected software developed by an independent company, Optimized Program Service (OPS), not associated with any single manufacturer or manufacturer's association. The engineering analysis design runs span a broad range of efficiencies from lowest first cost to maximum technologically feasible. The data used in the engineering analysis is discussed in Chapter 5 of the TSD.

1. Engineering Analysis Methodology

There exist certain fundamental relationships between the kVA ratings of transformers and their physical size and performance. Termed the ''0.75 scaling rule,'' these size-versus-performance relationships arise from equations describing how a transformer's cost and efficiency change with kVA rating. The Department used the 0.75 scaling rule to reduce the number of units that needed to be analyzed for establishing minimum efficiency standards for distribution transformers as a whole. The findings on those units analyzed were later scaled to other kVA ratings using the 0.75 scaling rule. To maintain the accuracy of the 0.75 scaling rule, DOE established engineering ''design lines.'' Each design line consists of distribution transformers that have a full range of kVA ratings and that have similar construction and engineering principles. Some design lines consist of an entire product class, but none spans more than a product class. The Department then selected one representative unit from each of these design lines for analysis. The 0.75 scaling rule was a critical underlying factor in the engineering analysis, since it enabled DOE to reduce the number of units analyzed to 10. Discussion on use of the 0.75 scaling rule can be found in TSD Chapter 5, section 5.2.2. Technical detail on the derivation of the 0.75 scaling rule can be found in TSD Appendix 5B.

In the ANOPR, the Department solicited comments on the use of the 0.75 scaling rule. 69 FR 45416. ASE and ODOE wrote that they support the use of the 0.75 scaling rule, and believe it is the correct and necessary approach to simplify the analysis. (ASE, No. 52 at p. 3 and No. 75 at p. 3; ODOE, No. 66 at p. 4) HVOLT commented at the ANOPR public meeting that the 0.75 scaling rule was used to develop the NEMA TP 1 tables, and there have been no major complaints about it. (Public Meeting Transcript, No. 56.12 at p. 92) PEMCO commented that it routinely uses the 0.75 scaling rule in its business operations, and that the rule works for scaling component costs for consistent construction practice and within reasonable size differences. PEMCO cautioned, however, that the higher the voltage class of the windings and the closer to the lower end of a kVA product range, the greater the error from the 0.75 scaling rule. (PEMCO, No. 57 at p. 1) The Department appreciates this comment from PEMCO, as it had created the engineering design lines to minimize error, particularly with respect to the medium-voltage, dry-type BIL groupings. In addition to the three BIL groupings, the Department also subdivided some of the product classes into two or more engineering design lines, so the kVA rating of the representative unit would not be scaled more than an order of magnitude up or down in any one design line. It took both of these steps to minimize any error from scaling, and to provide a more robust analytic foundation for the proposed standards. Based on these comments and the cautionary note from PEMCO, the Department will continue to apply the 0.75 scaling rule to extrapolate findings to those kVA ratings not specifically analyzed within each of the design lines.

Another critical issue on which stakeholders commented pertained to the use of OPS software in the development of the Department's database of transformer designs. HVOLT commented that the Department's percentage cost increases for the 25 kVA pole-type transformer were not large enough. It believes that the percentage cost difference between the standard levels considered should be greater. (HVOLT, No. 65 at p. 2) The Department appreciates this comment, and looked carefully at all the OPS software inputs and results, and discussed these with individual manufacturers during site visits in 2005. The Department recognizes that the manufacturer selling prices in the ANOPR base case for the 25 kVA unit were too high, and that the percentage increase from a larger base price would be smaller for the same absolute dollar cost increase. Following revisions to the engineering analysis for the 25 kVA liquid-immersed, pole-type transformer, the baseline unit manufacturer selling price decreased from around $800 to approximately $500 and, as a result, the percentage change in manufacturer selling prices between efficiency values has increased.

FPT expressed concern that the manufacturer selling prices for dry-type transformers may rise more rapidly than is represented in the engineering analysis. FPT is concerned that this may skew the decision-making process regarding what efficiency levels are cost-justified. (FPT, No. 64 at p. 2) Similarly, Howard commented that it believes the inputs and outputs of the OPS program are inaccurate, since it found the outputs of the software to be different from its own calculations. Howard expressed concern at the number of compromises, generalizations, and assumptions that could dilute the effectiveness of the results. (Howard, No. 70 at p. 3) NEMA commented that, because LCC results seem to justify standards higher than TP 1, the OPS design software may not be accurately modeling real-world units. (NEMA, No. 48 at p. 2) NEMA also commented that it had tested an actual unit that had a similar technical specification to an OPS design, and found different results than were reported by the Department. NEMA noted that the designs in the Department's database were not built and tested, and therefore are not representative of real transformers. (Public Meeting Transcript, No. 56.12 at p. 35) In a written submission, NEMA provided further detail on this comparison, and again questioned the real-world predictive capabilities of the software used. (NEMA, No. 60 at p. 3)

In response to these comments, the Department reviewed and refined the inputs to the OPS software in consultation with transformer manufacturers, OPS, and the Department's technical experts. It is important to recognize that there are many inputs to both the engineering and the LCC analytical models. For both analytical models, the Department updated its data and cost estimates for the NOPR analysis. These refinements changed the resulting designs and associated manufacturer selling price-efficiency relationships discussed in section IV.B of today's notice and Chapter 5 of the TSD.

The Department appreciates and thanks NEMA and its members for taking the time to locate and test a transformer that was similar to the one published. The Department found two critical problems with the comparison made. First, the design NEMA reviewed was not one DOE used in the ANOPR engineering analysis, but rather a draft design produced for comment two years before the ANOPR, in August 2002. Based on stakeholder feedback on that draft design, DOE modified the inputs to the OPS software when generating the ANOPR engineering database; thus, that design was not included. Second, the two designs NEMA compared, while having the same kVA rating, were not similar transformers. The OPS design and the unit NEMA tested had different BIL ratings and would be grouped in different product classes; therefore, different testing results would be expected.

Concerning the comments on the accuracy of the OPS software, the Department recognizes that differences between the Department's engineering analysis results and those of manufacturers can be caused by a number of factors, including different material prices, labor estimates, modeling parameters (e.g., impedance range, inductance), markups, and the consideration of different non-active transformer components (e.g., gauges, tanks). The Department discussed its inputs both in the ANOPR and during the manufacturer site visits, and revised them as necessary to be the best approximation of real-world practices. In the process of verifying the OPS software, DOE found that, under similar input conditions and modeling parameters, the cost and performance estimates in the Department's database are consistent with real-world transformer designs. This was verified both by comparing designs during manufacturer interviews in May 2005 and through a tear-down analysis of six transformers. The Department purchased six 75 kVA three-phase, low-voltage, dry-type transformers, and had the units tested, disassembled, and analyzed. It then used the OPS software to model the physical designs and generate an electrical analysis report. The OPS software accurately predicted the actual performance of the six transformers. In addition, using the 2000–2004 average material prices, the Department calculated the manufacturer selling prices for each of these six units using the same method as it used for the engineering analysis. The Department found that the cost-efficiency relationship (slope) for these six units tracked the cost-efficiency relationship developed for the NOPR analysis. A description of this tear-down analysis and its results can be found in TSD Chapter 5, section 5.7.

In addition to consulting with manufacturers and conducting a tear-down analysis, the Department arranged for a third-party transformer design engineer to prepare transformer designs based on the same inputs as those used by OPS. The transformer design engineer looked at three of the representative units published in this NOPR, and prepared designs at a low-first-cost, TP 1, and high-efficiency point. The Department then compared these designs to the OPS output for those same kVA ratings on an efficiency and manufacturer's selling price basis. It found that the transformer engineer's designs tracked the cost and efficiency improvements of the OPS designs. This work is discussed in Chapter 5 of the TSD.

The Department is confident of the accuracy of the OPS software, given the above-mentioned: (1) Comparison of engineering results with manufacturers during interviews; (2) tear-down analysis; (3) comparison of OPS designs with those of a third-party design engineer; and (4) discussions with manufacturers who use the OPS software and consulting services.

The Department received a few comments from stakeholders concerning the design lines and the representative units selected from those design lines. ACEEE commented that additional design lines may be necessary to better represent all transformers and better identify the lowest life-cycle cost points. ACEEE recommended looking at single-phase, liquid-immersed distribution transformers between 50 kVA and 500 kVA and three-phase units below 150 kVA. (ACEEE, No. 76 at p. 1 and Public Meeting Transcript, No. 56.12 at p. 27) In response to this comment, the Department reviewed its design lines and selection of representative units for the NOPR. Concerning an additional representative unit between 50 kVA and 500 kVA, the Department does not believe one is required. The 50 kVA (and 25 kVA pole-mounted) unit scales up to a maximum of 167 kVA—including the 75 kVA, 100 kVA, and 167 kVA rated units. The 500 kVA unit scales down to only two ratings, 250 kVA and 333 kVA. Use of the 0.75 scaling rule within these ranges is reasonable and accurate. Concerning an additional representative unit in the three-phase, liquid-immersed product class below 150 kVA, the Department also does not believe such an addition is necessary or would substantially improve the analysis. The 150 kVA unit is scaled down to 15 kVA, which is the maximum range over which the Department applies the 0.75 scaling rule in its analysis (one order of magnitude). The Department believes the 0.75 scaling rule is reasonable and accurate at this range. Additionally, creating an additional design line and analyzing a representative unit at kVA ratings below 150 kVA for three-phase, liquid-immersed transformers would not significantly improve the analysis. The shipments of three-phase, liquid-immersed transformers below 150 kVA represent just 1.6 percent of all three-phase, liquid-immersed units shipped, and a fraction of a percent of the liquid-immersed product classes. Therefore, the Department did not add any new representative units to the NOPR engineering analysis.

The Department received one comment concerning the treatment of medium-voltage, less-flammable, liquid-immersed transformers in the engineering analysis. Cooper Industries recommended that the Department consider combining these units as design option combinations in product classes 5 through 10 (the medium-voltage, dry-type product classes). Cooper Industries noted that less-flammable, liquid-immersed transformers are used in the same applications as dry-type transformers and are recognized for this application in the National Electrical Code. (Cooper, No. 62 at p. 2) As discussed in the ANOPR, the Department considers liquid-immersed and dry-type transformers as separate product classes. 69 FR 45385. It based this decision on input from several manufacturers during site visits in 2002, a review of industry standards—including those published by the Institute of Electrical and Electronics Engineers, Inc. (IEEE), the NEMA TP 1–2002 voluntary standard, and four comments received from stakeholders on the distribution transformer Framework Document. (Howard, No. 4 at p. 2; NEMA, No. 7 at p. 5; TXU Electric and Gas, No. 12 at p. 5; ACEEE, No. 14 at p. 2) All of these stakeholders advised the Department to treat liquid-immersed and dry-type distribution transformers separately when establishing standards.

Countering the separate treatment of liquid-immersed and dry-type transformers, Cooper asked that less-flammable, liquid-immersed units (a special type of liquid-immersed transformer) be evaluated for standards along with medium-voltage, dry-type units, because they can be used in the same applications. The Department appreciates this comment. However, energy efficiency standards are prescribed on the basis of differences in features that affect energy use. (42 U.S.C. 6295(q)) An example of these different features is the cooling mechanism for a transformer coil, whether it is air-cooled or liquid-cooled. Standards are therefore not classified or organized on the basis of whether they can service the same application. That said, customer applications are taken into consideration for the Department's economic analysis when a standard is developed and proposed (see the LCC analysis, TSD Chapter 8). Thus, due to the fact that the efficiency standard is applied on the basis of product class, not application, the Department did not incorporate less-flammable, liquid-immersed units into the medium-voltage dry-type analysis. The Department invites comment on this issue and on the recommendation from Cooper.

2. Engineering Analysis Inputs

One of the critical issues identified by many stakeholders commenting on the ANOPR analysis was whether DOE used prices that were representative of current material prices. Georgia Power commented that future transformer pricing may be affected by the decreasing number of suppliers of transformer materials—such as mineral oil and core steel—and that those still in business are already operating at full capacity. At present there are only two domestic suppliers of core steel: AK Steel and Allegheny Ludlum Steel Corporation (see TSD Appendix 3A). Georgia Power noted that higher-efficiency transformers will require more of these materials, which may result in material shortages. It is concerned that this situation could have a major impact on future transformer pricing and availability. (Georgia Power, No. 78 at pp. 1–2) HVOLT submitted a similar comment, and mentioned specifically that material prices have risen dramatically in step with higher energy prices. HVOLT noted that virtually all material suppliers now impose surcharges on top of their base material prices to yield the net selling price. HVOLT recommended the Department conduct a more detailed analysis of material prices. (HVOLT, No. 65 at pp. 2–3)

HVOLT and Edison Electric Institute (EEI) commented that material prices at the time of the ANOPR public meeting (September 2004) had increased relative to the material prices the Department used for its ANOPR analysis (2001 prices). (Public Meeting Transcript, No. 56.12 at p. 77; EEI, No. 63 at p. 3) The Southern Company commented that there have been substantial price increases in many of the materials used to build transformers, including copper and steel, and suggested that these increases make high-efficiency transformers less cost-effective. Southern recommended that recent raw material price increases and reasonable projections of future prices be included in the updated cost study produced for the NOPR. (Southern, No. 71 at p. 3) The National Rural Electric Cooperative Association (NRECA) commented that it supports and concurs with EEI's comments on the dramatic increase in the prices of steel and copper in the last two years. (NRECA, No. 74 at p. 2) In line with these statements, ERMCO commented that the 2004 material prices presented at the ANOPR public meeting looked reasonable, although prices for mineral oil and wire (both aluminum and copper) had increased substantially in the last month. ERMCO recognized that material prices are volatile, and again emphasized the cost increase for mineral oil. (ERMCO, No. 58 at p. 2)

In response to these comments and concerns about the increases in material prices (many of which were also provided to the Department verbally during the 2005 manufacturer site visits), the Department conducted two material pricing scenarios for the NOPR, covering core steel, conductors, insulation, and other key material inputs (see TSD Chapter 5, section 5.4). One, the reference case scenario, uses a five-year average of prices for these materials for the years 2000 through 2004. This scenario averages some of the material price volatility in the market, including low and high material price points that occurred during that time period. The second scenario is a ''current'' material price analysis, using material prices from the first quarter of 2005. This scenario provides a snapshot in time of material prices that were of concern to the stakeholders who submitted comments to the Department. When establishing a standard that will apply to all distribution transformers manufactured after a date several years in the future (here, January 1, 2010), the Department believes a material price that incorporates average pricing over a time period is a better basis for establishing the standard than using the material prices that manufacturers typically pay in any one year. Thus, DOE used the reference case (five-year average of material prices) as the basis for the standards proposed today. The engineering analysis results based on the material price reference case can be found in TSD Chapter 5. The Department also calculated engineering analysis and LCC analysis results based on the current (first quarter 2005) material price scenario; these are provided in TSD Appendix 5C.

In addition, the Department worked to gain a better understanding of the electrical core steel market, which is the main cost driver behind the construction of distribution transformers. It conducted interviews with both domestic core steel providers, two national steel wholesalers, and two manufacturers of equipment that processes core steel. The Department also reviewed publicly available information on the steel market in general, including trends, pressures, and constraints, such as input substitution opportunities and the supply-demand effects of Chinese economic growth. The findings of the Department's study of the electrical core steel market can be found in TSD Appendix 3A. The Department used the information from this research to improve its understanding of the core steel market and to verify the comments received from stakeholders concerning the recent trend toward increases in material prices, specifically electrical core steel.

During the ANOPR public meeting, ERMCO recommended that the Department consider the impacts of tariffs on the availability (and cost) of speciality steels. (Public Meeting Transcript, No. 56.12 at pp. 243–244) The Department did consider the import duty on raw (un-worked) Japanese core steel, specifically mechanically scribed, deep-domain refined, core steel (ZDMH). For discussion on the treatment of ZDMH core steel in this analysis, see TSD Chapter 5.

The Department also received a comment on the labor inputs used in the engineering analysis. FPT commented that the labor calculations in the ANOPR analysis for cutting and stacking core steel were incorrect. It stated that the labor rates should not be based on hours/inch, because of the different thicknesses of core steel. Stacking thinner laminations of steels takes longer because more pieces of material must be handled for each inch of core stack. (FPT, No. 64 at pp. 1–2) The Department agrees with this comment and modified the methods used in the engineering analysis for calculating the labor costs. The revised method and stacking rates DOE used for the various grades of steel are described in TSD Chapter 5.

3. Engineering Analysis Outputs

DOE received two comments on the energy losses associated with auxiliary devices. During the ANOPR workshop, Ameren commented that the Department should include the impact of losses from accessories in its calculation and determination of national energy savings. (Public Meeting Transcript, No. 56.12 at p. 254) ERMCO also commented on this subject, requesting that an allowance be made for protective devices for transformers (e.g., circuit breakers), which are sometimes specified by utility companies. In its comment, ERMCO suggested two possible approaches: (1) Have a separate table of efficiency ratings for transformers with protective devices, or (2) do not include any losses due to protective devices in the measurement of efficiency of the transformer. (ERMCO, No. 58 at p. 1) The Department notes that the measurement and representation of the efficiency of regulated transformers is prescribed in the test procedures for distribution transformers. 10 CFR Part 431, Subpart K, Appendix A; 71 FR 24972. As published, the test procedure directs manufacturers to provide an efficiency representation for a regulated unit that does not include losses from protective devices. The efficiency standard proposed today only governs the performance of the basic transformer; it would not apply to the protective devices and would not seek to regulate the efficiency of these devices. The test procedure directs manufacturers to either calculate and deduct losses from these protective devices, or to by-pass the protective devices in the load-loss test set-up configuration.

HVOLT, NEMA, and ODOE commented on manufacturer selling prices. HVOLT commented during the ANOPR workshop that the actual selling prices of liquid-immersed units are lower than was reported in DOE's analysis. (Public Meeting Transcript, No. 56.12 at p. 78) HVOLT also later stated that the price for a low-first-cost 25 kVA single-phase, pole-mount transformer was on the order of $400, while the Department's analysis reported $800. (Public Meeting Transcript, No. 56.12 at p. 96) NEMA recommended that the Department contact individual manufacturers and discuss the pricing of their lowest-first-cost transformers to calibrate the engineering analysis. (NEMA, No. 48 at p. 2 and Public Meeting Transcript, No. 56.12 at p. 35) ODOE echoed the comment from NEMA, recommending that the Department check the pricing of transformers sold by manufacturers. (ODOE, No. 66 at p. 3) Following NEMA's and ODOE's recommendations, the Department spoke to individual manufacturers (both NEMA members and non-NEMA members) about material pricing, manufacturers' selling prices, OPS software inputs, and other equipment costs (*e.g.*, tanks, bushings, busbar). The adjustments DOE made following these conversations resulted in a reduction in manufacturer selling prices for some design lines. For example, the low-first-cost design for the 25kVA single-phase, pole-mount transformer went from approximately $800 per unit to around $500 per unit using the five-year, average-material-price scenario.

DOE received two comments about the feasibility of manufacturing the most efficient designs produced in the engineering analysis. Cooper conducted a design analysis of the 50 kVA pad-mount, the 150 kVA three-phase, and the 1500 kVA three-phase, liquid-immersed units. It found that it was not possible to meet the ANOPR candidate standard level 5 (CSL5) efficiency level. Furthermore, it found that, as the design reaches ANOPR CSL3, the cost to produce the transformer generally increases exponentially. Because of this, Cooper believes that the OPS software does not account for realistic material performance characteristics or realize the cost or productivity impact of these design changes with regard to the manufacturing of a product. (Cooper, No. 62 at p. 1) NRECA also questioned the validity of the highest efficiency levels (ANOPR CSL4 and CSL5). It recommended that the Department verify whether transformers with these efficiencies actually exist or are merely theoretical designs on paper. (NRECA, No. 74 at p. 2)

As discussed in section IV.B.1, the Department took several steps to verify the OPS software and the predictive capability of the software to design transformers. The Department is confident in the accuracy of the OPS software, given the: (1) Comparison of engineering results with manufacturers during interviews; (2) tear-down analysis; (3) comparison of OPS designs with those of a third-party design engineer; and (4) discussions with manufacturers who use the OPS software and consulting services. In response to Cooper's and NRECA's comments on the maximum technologically feasible designs, the Department notes that the design option combinations that achieved the highest efficiencies in a given representative unit used non-traditional materials, such as amorphous material and laser-scribed, high-permeability, grain-oriented electrical steel. The core destruction factors, packing factors, and other real-world adjustments for production floor manufacturing are inputs that OPS has refined over decades in consultation with its clients, some of which have manufactured amorphous material and laser-scribed steel. If the core material, winding, and construction are all built to the design report specification, these are feasible designs. Details of the engineering analysis can be found in TSD Chapter 5 and Appendices 5A, 5B, and 5C.

C. Life-Cycle Cost and Payback Period Analysis

This section describes the LCC and payback period (PBP) analysis and the spreadsheet model DOE used for analyzing the economic impacts on customers. Details of the spreadsheet model, and of all the inputs to the LCC and PBP analysis, are in TSD Chapter 8. The Department conducted the LCC and PBP analysis using a spreadsheet model developed in Microsoft (MS) Excel for Windows 95 or above. When combined with Crystal Ball (a commercially available software program), the LCC and PBP model generates a Monte Carlo simulation to perform the analysis by incorporating uncertainty and variability considerations. While the Department included an annual maintenance cost as part of the LCC and PBP calculation, it assumed that maintenance and repair costs are independent of transformer efficiency.

The LCC is the total customer cost over the life of the equipment, including purchase expense and operating costs (including energy expenditures and maintenance). To compute the LCC, the Department summed the installed price of a transformer and the discounted annual future operating costs over the lifetime of the equipment. The PBP is the change in purchase expense due to an increased efficiency standard divided by the change in first-year operating cost that results from the standard. The Department expresses PBP in years. The data inputs to the PBP calculation are the purchase expense (otherwise known as the total installed consumer cost or first cost) and the annual operating costs for each selected design. The inputs to the transformer purchase expense were the equipment price and the installation cost, with appropriate markups. The inputs to the operating costs were the annual energy consumption and the electricity price. The PBP calculation uses the same inputs as the LCC analysis but, since it is a simple payback, the operating cost is for the year the standard takes effect, assumed to be 2010.

For each efficiency level analyzed, the LCC analysis required input data for the total installed cost of the equipment, the operating cost, and the discount rate. Table IV.2 summarizes the inputs and key assumptions used to calculate the customer economic impacts of various energy efficiency levels. Equipment price, installation cost, and baseline and standard design selection 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 effective 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.2 shows how the Department modified these inputs and key assumptions for the NOPR, relative to the ANOPR.

TABLE IV.2.—SUMMARY OF INPUTS AND KEY ASSUMPTIONS USED IN THE LCC AND PBP ANALYSES

Inputs	ANOPR description	Changes for NOPR
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 sales tax. Shipping costs were included for both types of transformers.	Reduced distributor markup for dry-type added small distributor markup for liquid-immersed.
Installation cost	Includes a weight-specific component, derived from *RS Means Electrical Cost Data 2002* and a markup to cover installation labor, and equipment wear and tear.	Added a pole replacement component to 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 50%, while for dry-type transformers, the fraction of evaluated purchases was 10%. The average A value for evaluators was $5/watt, while the B value depended on expected transformer load.	Increased liquid-immersed transformer evaluation percentage to 75%. Divided dry-types into (1) small-capacity medium-voltage and (2) large-capacity medium-voltage, with evaluation percentages of 50% and 80%, respectively.

TABLE IV.2.—SUMMARY OF INPUTS AND KEY ASSUMPTIONS USED IN THE LCC AND PBP ANALYSES—Continued

Inputs	ANOPR description	Changes for NOPR
Affecting Operating Costs		
Transformer loading	Loading depended on customer and transformer characteristics. The average initial liquid-immersed transformer loading was 30% for 25 dry-type kVA and 59% for 1500 kVA transformers. The average initial dry-type transformer loading was 32% for 25 kVA and 37% for 2000 kVA transformers. The shipment-weighted lifetime average loading was 33.6% for low-voltage, dry and 36.5% for medium-voltage, dry. With load growth, average installed liquid-immersed transformer loading was 35% for 25 kVA and 70% for 1500 kVA transformers with a shipment-weighted lifetime average loading of 52.9%.	Increased average peak loading for medium-voltage, dry-type transformers from 75% to 85%.
Load growth	1% 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 use and demand load simulation for liquid-immersed transformers, and estimated from the 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. Average marginal tariff-based retail electricity price: 6.4¢/kWh for no-load losses and 7.4¢/kWh for load losses. Average marginal wholesale utility hourly based costs: 3.8¢/kWh for no-load losses and 4.5¢/kWh for load losses.	Updated tariff-based electricity prices with 2004 tariff data. Adjusted hourly based electricity prices for inflation.
Electricity price trend	Obtained from *Annual Energy Outlook 2003* (*AEO2003*)	Updated to *AEO2005*.†
Maintenance cost	Annual maintenance cost did not vary cost as a function of efficiency	No change.
Affecting Present Value of Annual Operating Cost Savings		
Effective date	Assumed to be 2007	Assumed to be 2010.
Discount rates	Mean real discount rates ranged from 4.2% for owners of pole-mounted, liquid-immersed transformers to 6.6% for dry-type transformer owners.	No change.
Lifetime	Distribution of lifetimes, with mean lifetime for both liquid and dry-type transformers assumed to be 32 years.	No change.
Candidate Standard Levels		
Candidate standard levels	Five efficiency levels for each design line with the minimum equal to TP 1 and the maximum from the most efficient designs from the engineering analysis.	Six efficiency levels with the minimum equal to TP 1 and the maximum from the most efficient designs from the engineering analysis. Intermediate efficiency levels for each design line selected using a redefined set of LCC criteria (see section III.D.1.b).

* The concept of using A and B loss evaluation combinations is discussed in TSD chapter 3, Total Owning Cost Evaluation. Within the context of the LCC analysis, the A factor measures the value to a transformer purchaser, in $/watt, of reducing no-load losses while the B factor measures the value, in $/watt, of reducing load losses. The purchase decision model developed by the Department mimics the likely choices that consumers make given the A and B values they assign to the transformer losses.

† The Department is aware of *AEO2006,* and the electricity price forecast does not differ significantly from *AEO2005.*

The following sections contain brief discussions of the methods underlying each of these inputs and key assumptions in the LCC analysis. Where appropriate, the Department also summarizes stakeholder comments on these inputs and key assumptions and explains how it took these comments into consideration.

1. Inputs Affecting Installed Cost

a. Equipment Price

The equipment price of a transformer reflects the application of supply-chain markups, and the addition of sales tax and shipping costs, to the manufacturer's selling price. The markup is the percentage increase in price as the transformer passes through the distribution channel. Commercial and industrial customers most often purchase dry-type transformers from electrical contractors who purchase the transformers through distributors, whereas many liquid-immersed transformers are purchased by utilities directly from manufacturers and installed directly by utility staff. Therefore, DOE's markups for liquid-immersed transformers are smaller than those for dry-type transformers. In addition to the supply-chain markups, DOE's equipment prices include shipping costs and sales tax for both types of transformers. The Department did not have sufficient data to diversify the distribution channels and markups beyond these two general categories. Details of the installed cost inputs can be found in TSD Chapter 7.

In the ANOPR analysis, the Department assumed that all liquid-immersed transformers were purchased directly from manufacturers by utilities. NEMA commented that distribution channels are more complex than DOE assumed in the ANOPR analysis. It noted that some liquid-immersed units may go through distributors and some dry-type units may be sold directly from the manufacturer. NEMA also indicated that small transformers are more likely to go through distributors and large transformers are more likely to be sold directly. (NEMA, No. 48 at p. 2) NRECA commented that most, if not all, cooperative utilities purchase liquid-immersed transformers through distributors. (Public Meeting Transcript, No. 56.12 at p. 120) In response to NEMA's comment, the Department discussed distribution channels and markup practices with utility technical staff to obtain additional input for the NOPR analysis. Based on this input, the Department adjusted the distributor markup to 7 percent for liquid-immersed transformers and 15 percent for dry-type transformers. These distributor markup values compare with 0 percent and 35 percent, respectively, for the liquid-immersed and dry-type distributor markups for the more simplified distribution channels that the Department assumed for the ANOPR analysis.

b. Installation Costs

Higher-efficiency distribution transformers tend to be larger and heavier than less efficient designs. The Department therefore included the increased cost of installing larger, heavier transformers as a component of the first cost of efficient transformers. In the ANOPR, the Department presented the installation cost model and solicited comment from stakeholders. For details of the installation cost calculations, see TSD section 7.3.1.

EEI provided substantial comments regarding the installation cost implications of more-efficient transformers that are physically larger and heavier than less-efficient transformers. It asserted that transformer size and weight may require physical modification to pole structure or mounting pads, and that, in severe replacement applications, increased transformer size may require building and structural modifications. (EEI, No. 63 at pp. 4–5) NRECA expressed similar concerns that the size and weight of more energy-efficient transformers may dramatically affect installation cost. (NRECA, No. 74 at p. 2) Tampa Electric Company (TEC) commented that transformer efficiency standards must take into account physical dimension constraints to ensure compatibility with older units that will need to be replaced. (TEC, No. 77 at p. 1) Georgia Power Company commented that, as a result of the expected increase in physical size and weight of higher efficiency transformers, installation costs will be increased in several ways. First, it estimates that pole replacements will be required for 80 percent of the transformer replacement installations that have joint use applications (*e.g.*, telephone line, cable television) on the pole. Second, in addition to the pole replacements at existing locations, Georgia Power projects that numerous larger diameter and taller poles will be required at new transformer installations. Third, it asserts that an increase in the size and weight of pole-mounted and pad-mounted transformers will significantly increase utility costs, and that this impact will be proportional to the percent increase in transformer size and weight resulting from the higher efficiency requirements. (Georgia Power, No. 78 at pp. 2–3) Ameren also commented that it believes the Department should consider the economic impact of transformer weight increases, such as the necessity for using stronger poles, resulting from efficiency improvements. (Public Meeting Transcript, No. 56.12 at pp. 253–254)

Howard commented that higher efficiency transformers will be larger, resulting in increased shipping costs as well as handling problems for the installers. (Howard, No. 70 at p. 3) Comments from EEI included information from utility members of EEI, the American Public Power Association (APPA), and NRECA, who reported that in many cases increased transformer size and weight can affect the cost of new pole-mounted transformer installations; costs vary from utility to utility and depend on the size and weight increase. (EEI, No. 63 at pp. 20–62) Southern Company asserted that increases in installation costs from the weight increases of more-efficient transformers are not adequately covered in the ANOPR analysis. (Southern, No. 71 at p. 2) National Grid (NGrid) commented that high-efficiency transformers present utilities with logistical and financial challenges, but they have found that the benefits outweigh the costs when analyzed using a life-cycle cost analysis method employed in the industry. (NGrid, No. 80 at p. 1)

While the Department's ANOPR included weight- and size-dependent installation costs associated with the increased shipping, handling, labor, and equipment costs of installing larger and heavier transformers, the ANOPR did not include the costs of stronger poles or pole replacement. In response to stakeholder comments on pole-replacement costs, for the NOPR analysis the Department added a pole-replacement-cost function to the installation cost equation for design line 2, which covers pole-mounted transformers. This analysis assumed that a pole change-out cost of $2,000 occurs for up to 25 percent of pole-mounted transformers when the weight of the transformer exceeds 1,000 pounds. Because not all transformer installations require a change-out of existing equipment even in the most extreme case, the Department assumed a maximum change-out fraction. The Department selected 25 percent as the maximum change-out fraction estimate based on stakeholder input. (EEI No. 63 at p. 25)

c. Baseline and Standard Design Selection

A major factor in estimating the economic impact of a proposed standard is the selection of transformer designs in the base case and standards case scenarios. A key issue in the selection process is the degree to which transformer purchasers take into consideration the cost of transformer losses (A and B factors) when choosing a transformer—both before and after the implementation of a standard. The purchase-decision model in the LCC spreadsheet selects which of the hundreds of designs in the engineering database are likely to be selected by transformer purchasers. The LCC transformer selection process is discussed in detail in TSD Chapter 8, section 8.2.

The Department received three types of comments on the design selection and purchase behavior modeled in the LCC spreadsheets: (1) Applicability of values used, (2) actual values that stakeholders have observed in the market, and (3) percent of customers who use the evaluation formulae. Concerning the applicability of values used, NRECA questioned whether the B factors relative to the A factors used in the LCC spreadsheet accurately represent the A and B factors for rural cooperatives. (NRECA, No. 74 at pp. 2–3) Ameren asserted that the A and B values used by the Department for the ANOPR analysis were not representative of Midwestern electric utilities. (Public Meeting Transcript, No. 56.12 at p. 113) NEMA said that both manufacturers and utilities indicated at the public meeting that the A and B values assumed by the Department to characterize the base case were higher than those in current use, leading to a DOE base case that may reflect higher transformer efficiencies than marketplace reality. (NEMA, No. 60 at p. 2) ODOE also commented that the method the Department used to characterize the base case may result in higher average efficiencies than are actually found in the current market. ODOE believes that the value of losses is seldom a significant factor in purchase decisions for transformers. (ODOE, No. 66 at p. 5)

Regarding the actual values observed in the market, HVOLT commented that, for the 80 percent of electric utilities that currently evaluate losses when purchasing a liquid-immersed transformer, the A factor is between $2.00 and $2.50 and the B factor is approximately $0.75. HVOLT noted that these evaluation formulae are higher than the A factor ($1.57) and B factor ($0.57) used to develop the TP 1 standard. (Public Meeting Transcript, No. 56.12 at p. 107) AK Steel Corporation observed that some transformer customers evaluate with an A value of between $1.50 and $2.00. (Public Meeting Transcript, No. 56.12 at p. 109)

Relating to the percent of customers who use the evaluation formulae, BBF & Associates (BBF&A) said its market study in the early 1990s indicated that 90 percent or more of transformers were evaluated using A and B factors in the traditional approach. It pointed out that a subsequent survey in 2001–2002 showed that less than 50 percent were evaluated. (Public Meeting Transcript, No. 56.12 at p. 110) In the context of a discussion on liquid-immersed transformers, HVOLT said that around 80 percent of the market evaluates losses today. (Public Meeting Transcript, No. 56.12 at p. 107) For dry-type transformers, HVOLT suggested that there is probably less purchase evaluation than the Department assumed in the analysis, but that an estimate of 10 percent evaluators is probably accurate. (Public Meeting Transcript, No. 56.12 at p. 156) ACEEE stated that the efficiency of liquid-immersed transformers is dropping as utilities move away from evaluation of purchase decisions, due to regulatory uncertainty caused by restructuring of the electric utility industry. (ACEEE, No. 76 at pp. 1–2) Similarly, the Copper Development Association (CDA) observed that at the ANOPR public meeting, stakeholders commented that 62 percent of the smaller-kVA distribution transformers sold in 2002 were lowest-cost versions and several utility personnel indicated that A and B evaluation values were zero. CDA commented that it believes these statements illustrate that many transformers currently being purchased are lowest-first-cost, low-efficiency units. (CDA, No. 69 at p. 4)

The Department responded to these stakeholder comments regarding A and B values and the percent evaluators by using new data provided by stakeholders, and newly collected data from the Internet, to adjust the distributions and parameters it used to model purchase decisions (see TSD Chapter 8, section 8.3.1). It used data provided by NRECA and data collected from the Internet to revise its estimate of the mean A value to $3.85/watt compared to the value of $5/watt used in the ANOPR analysis. This addresses the stakeholder concerns that the A values used in the ANOPR analysis may have been high. With regard to the actual values, the Department characterized transformer loss evaluation with a distribution of A values that includes the lower range of values—$1.50/watt to $2.50/watt—mentioned by AK Steel. However, the data collected by the Department were inconsistent with HVOLT's assertion that 80 percent of electric utilities use an A factor between $2.00 and $2.50.

With respect to the percentage of evaluators, the Department obtained new data from NEMA regarding the percentage of transformers sold that are consistent with the voluntary TP 1 standard. The Department therefore adjusted the percentage of evaluators in its customer choice model to be consistent with the new data provided by NEMA. The Department believes that this method provides the most precise and detailed estimate of the percentage of evaluators that is consistent with actual market data.

The Department received several comments noting that shipments of TP 1-compliant transformers have recently increased, and noting the potential impact of States adopting TP 1 as their transformer standard. NEMA stated that its members' shipments of TP 1-compliant transformers increased in 2002 and 2003 compared to 2001 for all transformers considered in the scope of this rulemaking. (NEMA, No. 48 at p. 3) An EEI survey of nine of its members showed that an average of approximately 65 percent of liquid-immersed transformers purchased are already compliant with NEMA TP 1. (EEI, No. 63 at pp. 7–19) NGrid now purchases energy-efficient, liquid-immersed transformers that meet or exceed NEMA's TP 1 standard throughout its service territory in Massachusetts, Rhode Island, New Hampshire, and New York. This is true despite the fact that only Massachusetts requires TP 1-compliant, liquid-immersed transformers. (NGrid, No. 80 at p. 1) Georgia Power expressed doubt that the Department can accurately account for the number of transformers that are already purchased with NEMA TP 1 efficiencies. (Georgia Power, No. 78 at pp. 1–2)

The Appliance Standards Awareness Project (ASAP) and Northwest Power and Conservation Council (NPCC) commented that the base case should reflect the impact of State-established transformer standards. (Public Meeting Transcript, No. 56.12 at p. 248, Public Meeting Transcript, No. 56.12 at pp. 180–181) ODOE commented that the Department needs to pay careful attention to those States that have TP 1 as an existing standard because, by the time the DOE standard is published, States mandating TP 1 could represent a quarter to a third of transformer shipments. (Public Meeting Transcript, No. 56.12 at p. 185) NEMA said that, of those States that have adopted TP 1, most have done it for low-voltage, dry-type distribution transformers, so the other product classes would not be affected. (Public Meeting Transcript, No. 56.12 at p. 182)

In response to these comments, the Department obtained from NEMA new, detailed data regarding TP 1 compliance of shipped transformers. The Department adjusted the parameters of the customer choice model such that the base case TP 1 compliance in the LCC is consistent with the most recent NEMA data available to the Department.

Southern Company and ODOE requested that the Department provide the efficiency rating for the base case. (Public Meeting Transcript, No. 56.12 at p. 215 and p. 217) ACEEE agreed, noting that this information would enable further independent analysis of the cost and savings data. (ACEEE, No. 50 at p. 2 and No. 76 at p. 3) The Department complied with this request and reported the base case efficiencies for the ANOPR analysis in Supplemental Appendix 8E of the ANOPR TSD. These values have been updated for the NOPR analysis, and can be found in Appendix 8E of the TSD.

2. Inputs Affecting Operating Costs

a. Transformer Loading

Transformer loading is an important factor in determining which types of transformer designs will deliver a specified efficiency, and for calculating transformer losses. Transformer losses have two components: No-load losses and load losses. No-load losses are independent of the load on the transformer, while load losses depend approximately on the square of the transformer loading. Because load losses increase exponentially with loading, there is a particular concern that, during times of peak system load, load losses can impact system capacity costs and reliability. Details of the transformer loading models are presented in TSD Chapter 6.

For the ANOPR analysis, the Department estimated the loading characteristics of transformers by analyzing the statistics of available load data, and by assuming a distribution of initial annual peak loadings. ASE commented that the Department's analysis of load profiles is largely consistent with data provided by other stakeholders. It also recognized that the Department used publicly available data for utility loads, and commented that the average loadings for liquid-immersed transformers were reasonable. (ASE, No. 52 at p. 3 and No. 75 at p. 3) ODOE agreed with the transformer loads estimated by the Department based on ODOE's examination of loading studies conducted in the Pacific Northwest, which produced lower loading levels than expected by many analysts. (ODOE, No. 66 at p. 4)

HVOLT estimated that the average loading for dry-type, medium-voltage units is about 50 percent, with a daytime average of 60 percent and a nighttime average of 35 percent. (Public Meeting Transcript, No. 56.12 at pp. 131–132) HVOLT estimated that loading for liquid-immersed transformers is about 50 percent, but noted that loads in the residential sector can increase so much that loading can exceed the transformer nameplate rating. (Public Meeting Transcript, No. 56.12 at p. 131 and p. 133) In a written comment, HVOLT endorsed using loading assumptions identical to those for NEMA TP 1. HVOLT is not familiar with any publicly released loading studies that would alter the root mean square (RMS)-equivalent load of 50 percent load for medium-voltage transformers. (HVOLT, No. 65 at p. 3) EEI estimated that, according to three surveyed members, average loading levels range from 30 percent to 58 percent. A survey of eight members yielded a range of high-loading levels from 45 to 100 percent, and a range of low-loading levels from 35 to 75 percent. (EEI, No. 63 at pp. 7–19) TEC said that it strives to load transformers higher than the 50 percent level assumed by DOE, and recommended that the Department give consideration to efficiency ratings at higher loading levels. (TEC, No. 77 at p. 1)

The Department concluded that the ANOPR statistical loading analysis was largely consistent with stakeholder comments, with slight adjustments necessary for the loading levels of medium-voltage, dry-type transformers (see TSD Chapter 6, section 6.3.3.3). The Department increased the loading on medium-voltage, dry-type transformers in response to the comments by HVOLT, to be consistent with the relative difference in loading levels used by NEMA TP 1 between low-voltage and medium-voltage dry-type transformers.

On the issue of peak load coincidence, the Department received two comments. ASE agreed with the Department's peak load coincidence analysis for the ANOPR. (ASE, No. 52 at p. 3 and No. 75 at p. 3) The CDA commented that peak coil losses may have a high coincidence factor with system peaks. (CDA, No. 51 at pp. 3–4) The Department concluded that the statistical model used for peak loading in the ANOPR analysis was consistent with stakeholder comments and did not change peak loading statistics for the NOPR analysis.

b. Load Growth

The LCC takes into account the projected operating costs for distribution transformers many years into the future. This projection requires an estimate of how, if at all, the electrical load on transformers will change over time. For dry-type transformers, the Department assumed no load growth. For liquid-immersed transformers, the Department used as the default scenario a one-percent-per-year load growth. It applied the load growth factor to each transformer beginning in 2010, the expected effective date of the standard. To explore the LCC sensitivity to variations in load growth, the Department included in the model the ability to examine scenarios with zero-percent, one-percent, and two-percent load growth. Load growth is discussed in detail in TSD Chapter 8, section 8.3.6.

The Department received a range of comments on its load growth projections. CDA commented that loading on all transformers increases with time. It stated that, for liquid-immersed transformers, residential consumption per household has increased; for dry-types, commercial and industrial loads grow over time through more energy-intensive use of floor space and plant expansion. (CDA, No. 51 at pp. 1–2) ODOE stated that DOE should select a growth rate of zero, with sensitivity analysis at one-percent growth. (ODOE, No. 66 at p. 6) NEMA agreed with the Department's load growth estimates of zero percent for dry-type and one percent for liquid-immersed transformers. However, to the extent that building owners may defer transformer upgrades because of high unit costs, it noted that there may be some load growth on older, less efficient units. (NEMA, No. 48 at p. 2)

HVOLT commented that, in commercial and industrial complexes, new transformers are added to handle additional loads when there is an expansion, and there is not much information to suggest a substantial load growth on those transformers. (Public Meeting Transcript, No. 56.12 at p. 40) HVOLT also stated that one-percent load growth for liquid-immersed transformers seems too high. (Public Meeting Transcript, No. 56.12 at p. 138) HVOLT also said that there is not much load growth in residential applications, since transformers are installed in a community with a cluster of homes, they come online quickly, and after that, there are few factors producing load growth for the rest of the transformer's life. (Public Meeting Transcript, No. 56.12 at p. 39)

The Department retained its estimate of zero-percent load growth for dry-type transformers and one-percent load growth for liquid-immersed transformers. While some stakeholders disagreed with the Department's estimate of load growth for liquid-immersed transformers, data showing both growth in per-customer electrical loads over time and increasing transformer sizes purchased by utilities support the Department's approach (see TSD Chapter 8).

Regarding another aspect of the issue of load growth over time, EEI stated its concern that, because of load growth, higher efficiency transformers optimized to the loading point prescribed by the test procedure may have higher coil losses after being in service for several years. That is, EEI is concerned that the ''balance point'' between higher coil losses and lower core losses may not be reached until late in the operating life of a transformer. (EEI, No. 63 at pp. 3–4) Both the ANOPR and NOPR load analyses were responsive to this comment. The Department's estimate of losses tracked losses based on estimates of actual loads rather than test procedure loads. Both near-term and long-term losses were included in LCC estimates, with a weighting determined by the customer discount rate (see TSD Chapter 8).

c. Power Factor

The power factor is real power divided by apparent power. Real power is the time average of the instantaneous product of voltage and current. Apparent power is the product of the RMS voltage and the RMS current. For the ANOPR, the Department used a power factor of 1.0. A detailed discussion of the power factor can be found in TSD Chapter 8, section 8.3.12.

The Department received two comments on power factor. Southern Company commented that the power factor should be less than 1.0. (Public Meeting Transcript, No. 56.12 at p. 164) NEMA, on the other hand, stated that a power factor assumption of 1.0 is appropriate. (NEMA, No. 60 at p. 2)

While the Department agrees with Southern Company that actual power factors are less than 1.0, they are very close to 1.0, and the Department agrees with NEMA that use of a power factor of 1.0 is appropriate for the analysis of the efficiency standard. Using a power factor less than 1.0 would slightly increase the estimated losses for transformers, but would complicate the Department's analysis and affect all components of the Department's analysis where losses are estimated. The Department determined that the disadvantages of complicating the analysis by using an estimated distribution of slightly lower power factors outweighed the slight increase in analytical accuracy that could result.

d. Electricity Costs

The Department needed estimates of electricity prices and costs to place a value on transformer losses for the LCC calculation. As noted earlier, the Department created two sets of electricity prices to estimate annual energy expenses for its ANOPR: 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 (see TSD Chapter 8).

Southern Company questioned whether wholesale electricity prices are the correct prices for liquid-immersed transformers, and suggested that the Department consider the availability of very inexpensive electricity generating capacity in some regions. (Public Meeting Transcript, No. 56.12 at p. 125 and pp. 237–238) The Department's analysis for both the ANOPR and the NOPR estimated the marginal, or incremental, wholesale cost of electricity. The Department agrees with Southern Company that inexpensive electricity generating capacity exists in many regions of the country. The Department modeled a national distribution of generation capacity costs by estimating the marginal capacity cost of new generation as a function of the type of plant serving the capacity and the utility cost of capital which the Department obtained from a representative national sample of utilities (see TSD Chapter 8).

e. Electricity Price Trends

For the relative change in electricity prices in future years, DOE relied on price forecasts from the EIA's *Annual Energy Outlook (AEO)*. For its ANOPR, the Department used price forecasts from the *AEO2003*, the most recent price forecasts available at the time. The application of electricity price trends in the NOPR analysis is discussed in detail in TSD Chapter 8, section 8.3.7.

ODOE and HVOLT commented that the price forecasts used by the Department were too low. (ODOE, No. 66 at p. 4; Public Meeting Transcript, No. 56.12 at p. 38) Some stakeholders stated that more volatility should be added to the forecasts. The Natural Resources Defense Council (NRDC) commented that DOE should consider a scenario where electricity prices increase unexpectedly. (Public Meeting Transcript, No. 56.12 at p. 45) The NPCC stated that the Department assumed a monotonic wholesale electricity market and should model forecasted prices with some volatility. (Public Meeting Transcript, No. 56.12 at p. 124) ODOE and ACEEE suggested that the price trends should be updated with the most recent *AEO* forecasts; ACEEE added that DOE should include a high electricity price scenario in the analysis. (ODOE, No. 66 at p. 4; ACEEE, No. 76 at p. 3) Counter to the above stakeholders, CDA and AK Steel thought the Department's price forecasts were reasonable. CDA commented that the Department was correct to assume a moderate rate of energy cost increases, although it also believes a higher rate could be justified given recent experience. (CDA, No. 51 at p. 3) AK Steel added that EIA's long-term electricity price forecasts are good. (Public Meeting Transcript, No. 56.12 at p. 128)

For the NOPR, the Department updated its price forecasts with trends from the *AEO2005* as recommended by stakeholders, and addressed other stakeholder concerns through use of sensitivity analysis. The Department believes that price forecasts from the *AEO* are the most reliable and credible estimates of future electricity prices. As compared to *AEO2003*, the price trends from *AEO2005* actually show slightly lower forecasted prices. During the writing of this notice, the EIA published *AEO2006*, but since the electricity price forecast did not differ significantly from *AEO2005*, the Department did not update its analysis results using *AEO2006*. The Department addresses stakeholder concerns regarding the possibility of higher electricity prices through the sensitivity section of the LCC analysis (see TSD Chapter 8). This analysis estimates LCC results under conditions where electricity prices are 15 percent higher than the Department's medium scenario. However, as in the ANOPR analysis, the Department retained the medium *AEO* forecast as the electricity price trend that is most credible and authoritative with respect to the analysis of the future economic impacts of efficiency standards.

3. Inputs Affecting Present Value of Annual Operating Cost Savings

a. Standards Implementation Date

The Department proposes that the new energy-efficiency standard for distribution transformers apply to all units manufactured three years or more after publication of the final rule. For the NOPR analysis, the Department assumed a 2007 final rule publication; hence a 2010 implementation or compliance date. The Department calculated the LCC for customers as if each new distribution transformer purchase occurs in the year manufacturers must comply with the standard.

Several comments called for acceleration of the rulemaking schedule. ACEEE said the NOPR should be published by July 2005 and the final rule six months later. (ACEEE, No. 76 at p. 4) The National Association of Regulatory Utility Commissioners (NARUC) urged DOE to establish a new standard for distribution transformers as soon as possible. (NARUC, No. 68 at pp. 2–5) NRDC asked DOE to make a commitment to a schedule, with appropriate milestones, that will allow a final rule to be issued no later than January 29, 2006. (NRDC, No. 61 at p. 3) ASE urged the Department to maintain an 18-month schedule to complete the rulemaking. (ASE, No. 52 at p. 1 and No. 75 at p. 1)

The Department understands that the rulemaking schedule impacts the date by which manufacturers of distribution transformers must comply with any new energy-efficiency standard. It is committed to completing the rulemaking in a timely fashion and expects to publish a final rule by September 2007.

b. Discount Rate

The discount rate is the rate at which future expenditures are discounted to estimate their present value. It is the factor that determines the relative weight of first costs and operating costs in the LCC calculation. Consumers experience discount rates in their day-to-day lives either as interest rates on loans or as rates of return on investments. Another characterization of the discount rate is the ''time value of money.'' The value of a dollar today is one plus the discount rate times the value of a dollar a year from now. The Department estimated consumer discount rates by calculating the consumer cost of capital (see TSD Chapter 8).

Discount rates depend on who is borrowing and at what scale. Thus, the discount rates in the LCC analysis are different than those in the national impact analysis. This section discusses consumer discount rates that the Department used in the LCC analysis.

With respect to consumer discount rates in the ANOPR, stakeholders expressed a diversity of views regarding which discount rates are appropriate for the LCC analysis. ASE and ODOE commented that the Department should use a three-percent real discount rate, similar to the discount rate used by the California Energy Commission (CEC) in recent State-level energy efficiency analyses. (ASE, No. 75 at p. 3; ODOE, No. 66 at p. 5) NRDC said that the Department's use of discount rates exceeding 5.5 percent real conflicts with the explicit instructions in *NRDC* v. *Herrington*, because of the court's instruction to consider payback times of less than nine years as economically justified. (NRDC, No. 61 at p. 6) ACEEE commented that the Department's choice of discount rates for utilities was appropriate. (ACEEE, No. 76 at p. 3) HVOLT recommended that the Department set efficiency standards on a three-to five-year consumer investment return, to represent commercial customer preferences. (HVOLT, No. 65 at p. 3)

The Department examined each of these comments to see if any would lead to a more accurate description of consumer economic impacts. In examining the three-percent discount rate recommended by ASE and ODOE, the Department found that the CEC, in its rulemaking, estimated the consumer cost of capital using a method similar to that of the Department. However, the CEC analyzed a different class of consumers and used less detailed data. Therefore, the Department considers its discount rates to be more accurate for the distribution transformer energy-efficiency analysis than the discount rates estimated by the CEC for other products. The Department retained the consumer discount rates that it used in the ANOPR analysis, as shown in Table IV.3. The consumer discount rates shown in the table are based on a detailed analysis of risk-adjusted cost of capital for consumers, as described in TSD Chapter 8.

TABLE IV.3.—WEIGHTED-AVERAGE DISCOUNT RATES BY DESIGN LINE AND OWNERSHIP CATEGORY

		Transformer ownership category					
		Property owners	Industrial companies	Commercial companies	Investor-owned utilities	Publicly owned utilities	Government offices
Mean real discount rate		4.35%	7.55%	7.46%	4.16%	4.31%	3.33%
Design line	Weighted average discount rate (%)	Estimated ownership (%)					
1	4.24	0.4	0.5	0.9	72.0	26.0	0.2
2	4.24	0.4	0.5	0.9	72.0	26.0	0.2
3	4.40	2.1	2.4	4.5	80.0	10.0	1.0
4	4.24	0.4	0.5	0.9	72.0	26.0	0.2
5	5.38	9.5	9.5	27.0	35.0	15.0	4.0
9	6.56	19.0	19.0	54.0	0.0	0.0	7.9
10	6.56	19.0	19.0	54.0	0.0	0.0	7.9
11	6.56	19.0	19.0	54.0	0.0	0.0	7.9
12	6.56	19.0	19.0	54.0	0.0	0.0	7.9
13	6.56	19.0	19.0	54.0	0.0	0.0	7.9

4. Candidate Standard Levels

To conduct the LCC analysis, the Department first selected CSLs. Based on its examination of the CSLs, the Department then selected trial standard levels (TSLs). From those TSLs, it developed today's proposed standards. Cooper Power Industries commented that DOE should use a consistent method for all product classes to determine CSLs. (Cooper, No. 62 at p. 3) ASAP stated that DOE should examine a CSL with the maximum efficiency that maintains a positive economic impact for each product class. (Public Meeting Transcript, No. 56.12 at p. 218) ACEEE recommended that the Department examine TP 1 plus 0.2 percent, 0.3 percent, and 0.4 percent efficiency improvements for all design lines. It encouraged the Department to carefully examine the cost and other economic inputs, since the lowest life-cycle cost point, when compared to TP 1, varies significantly among design lines. (ACEEE, No. 76 at p. 1) ACEEE said that DOE should regroup the CSLs so that CSL 1 is TP 1, CSL 3 is the minimum life-cycle cost point, and CSLs 2 and 4 are slightly above and below the minimum LCC. (ACEEE, No. 50 at p. 1 and No. 76 at p. 2) ACEEE suggested that DOE realign the CSLs so that they have approximately equivalent economic performance. (Public Meeting Transcript, No. 56.12 at p. 26) EEI and NRECA recommended that DOE investigate CSLs that have rated efficiencies below TP 1, since many transformers in the current market have efficiencies below TP 1. (EEI, No. 63 at p. 2; NRECA, No. 74 at p. 2) Howard stated that it is appropriate to round candidate standard efficiency levels to one decimal place. (Howard, No. 70 at p. 3)

For the NOPR analysis, the Department complied with most of the stakeholder recommendations regarding standard levels. As requested by Cooper, DOE developed a consistent method for selecting standard levels for each design line. In response to the request by ASAP, the Department defined a standard level that represented the maximum energy savings with approximately no change in LCC. In response to ACEEE, the Department defined CSL 4 as the efficiency level with minimum LCC for each design line, and realigned CSLs 4 and 5 to have equivalent economic performance for each design line. The Department did not comply with EEI's and NRECA's requests to examine standard levels lower than TP 1 because—as described in this NOPR—the Department has found that efficiencies higher than or equal to TP 1 are economically justifiable, and thus the Department is obligated to pick a standard level that has efficiencies greater than or equal to TP 1. If the Department had reason to believe that any TP 1 levels were not economically justifiable for a standard, it would have examined efficiency levels below TP 1.

Table IV.4 lists the CSLs evaluated for each design line, expressed in terms of efficiency, and in terms relative to NEMA TP 1 efficiency levels.

TABLE IV.4.—CANDIDATE STANDARD LEVELS EVALUATED FOR EACH DESIGN LINE

Design line	CSL											
	1 TP 1		2 ⅓ of diff. between TP 1 and min LCC		3 ⅔ of diff. between TP 1 and min LCC		4 Min LCC		5 Max energy savings with no change in LCC		6 Max energy savings	
	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %	TP 1+ %	Effic'y %
1	0.0	98.9	0.14	99.04	0.29	99.19	0.43	99.33	0.59	99.49	0.69	99.59
2	0.0	98.7	0.03	98.73	0.06	98.76	0.09	98.79	0.26	98.96	0.76	99.46
3	0.0	99.3	0.08	99.38	0.16	99.46	0.24	99.54	0.44	99.74	0.45	99.75
4	0.0	98.9	0.18	99.08	0.36	99.26	0.55	99.45	0.68	99.58	0.71	99.61
5	0.0	99.3	0.06	99.36	0.12	99.42	0.17	99.47	0.41	99.71	0.41	99.71
9	0.0	98.6	0.22	98.82	0.44	99.04	0.66	99.26	0.81	99.41	0.81	99.41
10	0.0	99.1	0.12	99.22	0.23	99.33	0.35	99.45	0.41	99.51	0.41	99.51
11	0.0	98.5	0.17	98.67	0.34	98.84	0.51	99.01	0.59	99.09	0.59	99.09
12	0.0	99.0	0.12	99.12	0.23	99.23	0.35	99.35	0.40	99.40	0.40	99.40
13	0.0	99.0	0.15	99.15	0.30	99.30	0.45	99.45	0.55	99.55	0.55	99.55

5. Trial Standard Levels

The TSLs are the efficiency levels considered by the Department for the proposed standard. They are based on the CSLs selected for the LCC analysis. However, because of special considerations concerning manufacturer impacts and design lines (DLs) within the same product class, some efficiency levels for DL1 and DL4 are drawn from the same CSL. See TSD Chapter 10 for a more detailed explanation. Table IV.5 shows the mapping from the design line CSLs to the TSLs. In the LCC and LCC subgroups chapters of the TSD (Chapters 8 and 11), the Department reports results in terms of CSLs. In subsequent analyses (e.g., shipments in Chapter 9, national impacts in Chapter 10, MIA in Chapter 12) and in this NOPR, the Department reports all results in terms of TSLs, mapping the LCC results according to Table IV.5.

TABLE IV.5.—MAPPING OF THE CANDIDATE STANDARD LEVELS TO TRIAL STANDARD LEVELS

	DL1	DL2	DL3	DL4	DL5	DL9	DL10	DL11	DL12	DL13
TSL1	CSL1	CSL1	CSL1	CSL1	CSL1	CSL1	CSL1	CSL1	CSL1	CSL1
TSL2	CSL1	CSL2	CSL2	CSL2	CSL2	CSL2	CSL2	CSL2	CSL2	CSL2
TSL3	CSL1	CSL3	CSL3	CSL3	CSL3	CSL3	CSL3	CSL3	CSL3	CSL3
TSL4	CSL2	CSL4	CSL4	CSL3	CSL4	CSL4	CSL4	CSL4	CSL4	CSL4
TSL5	CSL3	CSL5	CSL5	CSL5	CSL5	CSL5	CSL5	CSL5	CSL5	CSL5
TSL6	CSL6	CSL6	CSL6	CSL6	CSL6	CSL6	CSL6	CSL6	CSL6	CSL6

Georgia Power asked whether the efficiency values shown in Table II.d of the ANOPR apply only to the representative transformer for each design line, or if that efficiency is applicable to all of the kVA sizes represented by that design line. It noted that the latter would be too restrictive. (Georgia Power, No. 78 at pp. 3–4) The ANOPR document did not provide efficiency levels for all kVA ratings in a product class or design line. For the NOPR, the Department provides a complete specification of the efficiency levels for all kVA ratings. Tables II.1 and II.2 of this NOPR express the efficiency ratings for all specific kVA ratings covered by today's proposed standard. This additional information also responds to a comment by ACEEE. ACEEE asked that the Department provide efficiency values for all the kVA ratings in between the representative units analyzed. (ACEEE, No. 50 at p. 2) The Department provides this information in TSD Chapter 8.

6. Miscellaneous Life-Cycle Cost Issues

In response to the ANOPR analysis, DOE examined several additional issues relating to the LCC. These issues are grouped for organizational clarity and completeness, and are discussed below.

a. Tax Impacts

The Department did not include the impact of income taxes in the LCC analysis for the ANOPR. The Department understands that there are two ways in which taxes affect the net impacts attributed to purchasing equipment that is more energy-efficient than baseline equipment: (1) Energy-efficient equipment typically costs more to purchase than baseline equipment, which lowers net income and may lower company taxes; and (2) more-efficient equipment typically costs less to operate than baseline equipment, which increases net income and may increase company taxes.

In general, the Department believes that the net impact of taxes on the LCC analysis depends on firm profitability and expense practices (i.e., how firms expense the purchase cost of equipment). In the ANOPR, the Department sought input on whether commercial income tax effects are significant enough to warrant inclusion in the LCC analysis. 69 FR 45396. ACEEE commented that income tax should not be included in the analysis, because it would significantly complicate the analysis, and it has found that many businesses do not pay income taxes due to the many credits and deductions that are available in the current tax code. (ACEEE, No. 76 at p. 4) ODOE stated that it believes the number of corporations actually paying income taxes has declined to the point where the overall impact of including income tax effects should be negligible. (ODOE, No. 66 at p. 6) Southern Company questioned how many firms do not pay income taxes. (Public Meeting Transcript, No. 56.12 at p. 164) NPCC stated that the analysis should be based on after-income-tax data, but also noted that businesses do not necessarily pay income tax. (Public Meeting Transcript, No. 56.12 at p. 158)

The Department agrees with ACEEE that the inclusion of income tax effects would significantly complicate the analysis. In analyzing the available options for including income tax effects, the Department could not find an estimation method where—with the existing data gaps—sufficient accuracy could be obtained to justify the increased analytical complexity. The Department therefore did not include an estimate of income tax impacts in the LCC analysis.

b. Cost Recovery Under Deregulation, Rate Caps

During the ANOPR review, stakeholders expressed mixed concerns regarding the potential impact of distribution transformer efficiency standards under utility deregulation. Southern Company commented that the impact on electric utilities of increasing the cost of transformers will vary depending on the regulatory scheme for the different utilities. It recommended that the Department include this issue in the analysis, especially for the utilities that are under rate cap legislation. (Public Meeting Transcript, No. 56.12 at p. 187) ODOE stated that there is a small likelihood of future electricity market deregulation and recommended that the Department ignore deregulation for the NOPR analysis. (ODOE, No. 66 at p. 5)

For the ANOPR, stakeholders stated many reasons why consumers may not be able to recover the added investment cost of higher efficiency distribution transformers. EEI expressed concern that political and economic risks related to deregulation will force utilities to make uneconomic (non-recoverable) incremental investments in efficient transformers. EEI requested that DOE include the effect of reduced utility earnings in the LCC analysis. (EEI, No. 63 at p. 4) ACEEE noted that utility representatives pointed out that some utilities currently have caps on their rates, which limit their ability to recover additional transformer costs. ACEEE expects that regulators would be supportive of cost recovery for reasonable transformer cost increases. (ACEEE, No. 76 at p. 3) NRDC commented that many utilities believe they cannot recover the additional costs associated with more-efficient transformers, but this will not be a problem because utility regulation throughout the country allows the distribution utility to achieve a regulated rate of return on all reasonable and prudent investment. NRDC noted that some utilities may find today's investments in high-efficiency transformers to be economically troublesome because they are subject to rate caps, but these rate caps all expire before the transformer efficiency standard would go into effect. New rate cases would then result in a new rate structure consistent with the standards-compliant transformer investments. (NRDC, No. 61 at pp. 7–8) ASE looked into the issue of rate caps and found that about 41 percent of electricity sales are in States with restructured electricity rate regulations, with about 27 percent of sales subject to rate caps, but that these caps expire steadily from 2005 to 2010. (ASE, No. 52 at p. 4) Georgia Power also asserted that utility companies cannot raise their prices to make up for the expected rise in transformer prices that will result from higher efficiency requirements without proceeding through the regulatory process. It stated, therefore, that DOE needs to weigh the financial burden this rulemaking may place on electric utilities before issuing a final rule. (Georgia Power, No. 78 at p. 4) NEMA also expressed concern that the entity paying the additional capital cost for a more energy-efficient transformer would frequently not be the beneficiary of the resultant energy cost savings. (NEMA, No. 48 at p. 1)

The concern expressed by stakeholders regarding the potential lack of cost recovery for distribution transformer investments is a classic example of ''split incentives'' for efficiency investments. A split incentive occurs when the entity that makes an investment is different from the entity that will receive the economic benefits of the investment. Split incentives prevent economically viable investments because, without receiving the benefits of an investment, the investor loses motivation to make investments that otherwise might have good returns. If the Department were to model split incentives in the LCC analysis, it would need to divide ownership of first costs and operating cost savings for a fraction of the transformers in the analysis. If the cost of capital were the same for the owner of the transformer and the owner of the operating cost savings, then the average LCC savings result would actually remain the same, although the spread of LCC savings in the LCC distribution results would increase. Some owners would only incur costs, while others would only receive benefits.

The Department decided not to explicitly model split incentives in the LCC analysis for the NOPR. Such modeling would have little impact on the total net LCC savings for the Nation. While the cost and the benefits would be divided between two different owners in the split incentive case, the sum would produce the same approximate net LCC savings as a model that does not include split incentives. The Department does, however, report the increase in first cost and the decrease in operating cost savings for each design line and efficiency level in TSD Chapter 8. Stakeholders can therefore evaluate the impact of standards under a split-incentive scenario where the increased transformer cost and the operating cost savings are owned by different entities.

c. Other Issues

HVOLT commented that DOE should consider incremental price compared to incremental benefit instead of total price to total benefit, where the increments are taken by comparing the results of one standard level to the results of the next highest standard level under consideration. (Public Meeting Transcript, No. 56.12 at p. 262) ACEEE stated that incremental analysis is not necessary. (Public Meeting Transcript, No. 56.12 at p. 158) The Department does not use incremental analysis in the evaluation of standards because of legal interpretations of the methodology it is required to follow. As described in section V.C of this NOPR, the Department followed its normal approach in selecting a proposed energy conservation standard for distribution transformers. It started by comparing the maximum technologically feasible level with the base case, and determined whether that level was economically justified. If it found the maximum technologically feasible level to be unjustified, the Department then analyzed the next lower TSL to determine whether that level was economically justified. The Department repeated this procedure until it identified a TSL that was economically justified. This procedure that the Department followed for selecting today's proposed standard level is that which the Department has historically determined is consistent with EPCA, as amended.

Georgia Power commented that the Department's calculations for the economic justification of, and energy savings associated with, higher-efficiency transformers are not applicable to every utility in the Nation. It noted that each utility is different and there are too many variables that cannot be accurately accounted for in such calculations. (Georgia Power, No. 78 at pp. 1–2) For the liquid-immersed design lines (1–5), Georgia Power analyzed the percentage change in price and TOC for several kVA sizes for each of the CSLs beyond TP 1. It found that, for all these cases, the TOC actually increased in contrast to the decrease in LCC found by the Department, indicating that the savings in energy do not economically justify the increase in first cost. (Georgia Power, No. 78 at pp. 4–5)

The Department recognizes that the TOC approach used by utilities can yield results that are substantially different from the Department's LCC analysis. The standard TOC approach used by electric utilities is typically calculated according to the regulatory mandates of cost recovery rate regulation. For cost recovery, the annual expenses associated with an investment in equipment need to be increased (or marked up) to generate revenue for those utility costs that may not be directly related to the equipment investments but still need to be recovered (*i.e.*, operation and maintenance expenses). This is formulated in terms of a fixed charge rate (FCR), which is used to calculate the annual revenue required to cover the expenses of a capital investment such that a utility can stay in business. The FCR used by utilities is generally larger than the revenues required to cover just the cost of capital. In the LCC analysis, DOE only accounted for the capital and investment expenses that are directly related to the purchase of the equipment being analyzed. The factor that represents the annual expenses required to recover capital costs is called the capital recovery factor (CRF) and is generally less than the FCR. The Department therefore recognizes that investments in efficiency that are economically justified under EPCA, as amended, may not be economically justified with respect to utility TOC evaluations that are performed under the assumptions of utility rate-setting regulation.

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

The national impact analysis evaluates the impact of a proposed standard from a national perspective rather than from the consumer perspective represented by the LCC. When it evaluates a proposed standard from a national perspective, the Department must consider several other factors that are not included in the LCC analysis. One of the primary factors the Department modeled in the national impact analysis was the gradual replacement of existing, less-efficient transformers with more-efficient, standard-compliant transformers over time. This rate of replacement was estimated by an equipment shipments model that describes the sale of transformers for replacement and for inclusion in new electrical distribution system infrastructure. A second major factor included in the national impact analysis was the fact that the national cost of capital may differ from the consumer cost of capital, and thus the discount rate used in the national impact analysis can be different from that used in the LCC. The third factor the Department included in the national impact analysis was the difference between the energy savings obtained by the consumer and the energy savings obtained by the Nation. Because of the effect of distribution and generation losses, the national energy savings from a proposed standard are larger than the sum of the individual consumers' energy savings. The details of the Department's national impact analysis are provided in Chapters 9 and 10 of the TSD.

During the ANOPR review, the Department received stakeholder comments on its approach to two of these three major factors. While it did not receive comments indicating any stakeholder disagreement with its accounting of national versus consumer energy savings, the Department did receive stakeholder comments concerning its shipments model and national discount rates.

Regarding DOE's shipments model, HVOLT commented that DOE considers the dry-type transformer market to have inelastic pricing, but that it actually is quite elastic and DOE should incorporate a price response that allows a shift to liquid-immersed transformers. (Public Meeting Transcript, No. 56.12 at pp. 173–174) NEMA agreed that dry-type transformers have price elasticity of demand, since deferring or foregoing investments may be a viable alternative for some customers. (NEMA, No. 48 at p. 1)

The Department agrees with HVOLT and NEMA that the sales of dry-type transformers are likely to be elastic. Since detailed shipments data that can be used for elasticity estimates are not available for dry-type transformers, the Department estimated elasticities using data from an economically similar commercial appliance—commercial air conditioners. Both commercial air conditioners and distribution transformers are integral elements of building and facilities electro-mechanical design and construction, and are installed during building construction and rehabilitation. The shipments elasticity scenarios the Department examined are provided in Table IV.6, and are explained in more detail in TSD Chapter 9.

TABLE IV.6.—SUMMARY OF SHIPMENTS MODEL INPUTS

Input	ANOPR description	Changes for NOPR
Shipments data	Third-party expert (HVOLT) for the year 2001	No change.
Shipments backcast	For years 1977–2000, used Bureau of Economic Analysis' (BEA) manufacturing data for distribution transformers. Source: *http://www.bea.doc.gov/bea/pn/ndn0304.zip*. For years 1950–1976, used EIA's electricity sales data. Source: *http://www.eia.doe.gov/emeu/aer/txt/stb0805.xls*.	Added three more years of BEA's manufacturing data—for years 2001 through 2003.
Shipments forecast	Years 2002–2035: Based on *AEO2003*	Years 2010–2038: Based on *AEO2005*.
Dry-type/liquid-immersed market shares.	Based on EIA's electricity sales data and *AEO2003*	Based on EIA's electricity sales data and *AEO2005*.
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.

TABLE IV.6.—SUMMARY OF SHIPMENTS MODEL INPUTS—Continued

Input	ANOPR description	Changes for NOPR
Elasticities	For liquid-immersed transformers: • Low: 0.00 • Medium: −0.04 • High: −0.20 For dry-type transformers: • 0.00	For liquid-immersed transformers: No change. For dry-type transformers: • Low: 0.00 • Medium: −0.02 • High: −0.20

A summary of the NES and NPV analytical model inputs are provided in Table IV.7. More detailed discussion on these inputs can be found in TSD Chapter 10.

TABLE IV. 7.—SUMMARY OF NES AND NPV MODEL INPUTS

Input	ANOPR description	Changes for NOPR
Shipments	Annual shipments from shipments model	No change.
Implementation date of standard.	Assumed to be 2007	Assumed to be 2010.
Base case efficiencies	Constant efficiency through 2035. Equal to weighted-average efficiency in 2007.	Constant efficiency through 2038. Equal to weighted-average efficiency in 2010.
Standards case efficiencies.	Constant efficiency at the specified standard level from 2007 to 2035	Constant at the efficiency at the specified standard level from 2010 to 2038.
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.	*AEO2003* forecasts (to 2025) and extrapolation for 2035 and beyond	Used *AEO2005* forecasts (to 2025) and extrapolation for 2038 and beyond.
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.
Analysis year	Equipment and operating costs are discounted to the year of equipment price data, 2001.	Equipment and operating costs are discounted to year 2004.

E. Commercial Consumer Subgroup Analysis

In analyzing the potential impacts of new or amended standards, the Department evaluates impacts on identifiable groups (i.e., subgroups) of customers, such as different types of businesses, which may be disproportionately affected by a national standard. For this rulemaking, the Department identified rural electric cooperatives and municipal utilities as transformer consumer subgroups that could be disproportionately affected, and examined the impact of proposed standards on these groups. The consumer subgroup analysis is discussed in detail in TSD Chapter 11.

The Department's selection of subgroups responded directly to comments received on the ANOPR. NRECA expressed concern that transformers servicing a single customer on a rural electric system may not be represented in the general LCC analysis. It requested the Department to take steps to include more data from cooperatives serving sparsely populated areas with long radial distribution lines. It commented that costs resulting from the DOE standard could increase to an unjustified level for rural electric cooperatives, which purchase relatively large numbers of transformers compared to their system load. (NRECA, No. 74 at p. 2) Southern Company commented that municipal utilities and rural electric cooperatives should be evaluated separately. (Public Meeting Transcript, No. 56.12 at p. 211) In its commercial consumer subgroup analysis, the Department analyzed municipal utilities and rural electric cooperatives separately, including additional data from cooperatives that serve sparsely populated areas with long radial distribution lines.

The results of the Department's commercial consumer subgroup analysis are summarized in section V.A.1.c below and described in detail in TSD Chapter 11.

F. Manufacturer Impact Analysis

1. General Description

The Department performed an MIA to estimate the financial impact of higher efficiency standards on distribution transformer manufacturers 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 customized for this rulemaking. The GRIM inputs are information regarding the industry cost structure, shipments, and revenues. The key output is the INPV. Different sets of assumptions (scenarios) produce different results. The qualitative part of the MIA addresses factors such as product characteristics, characteristics of particular firms, and market and product trends, and includes assessment of the impacts of standards on subgroups of manufacturers. The complete MIA is outlined in TSD Chapter 12.

The Department outlined the MIA approach in the ANOPR. 69 FR 45412. In section II.C. of the ANOPR, the Department asked stakeholders for comments on significant one-time additional costs manufacturers would incur if efficiency standards were introduced. 69 FR 45393. The MIA approach was also discussed at the September 28, 2004, ANOPR public meeting.

The Department conducted the MIA in three phases. Phase 1, ''Industry Profile,'' consisted of the preparation of an industry characterization. Phase 2, ''Industry Cash Flow,'' focused on the industry as a whole. In this phase, DOE used the GRIM to prepare an industry cash-flow analysis. The Department used publicly available information developed in Phase 1 to adapt the GRIM structure to facilitate the analysis of distribution transformer standards. In Phase 3, ''Subgroup Impact Analysis,'' the Department conducted structured, detailed interviews with six manufacturers. Two of the six manufacturers are small businesses (750 or fewer employees). Three of the manufacturers produce medium-voltage, dry-type transformers, collectively representing more than 70 percent of the U.S. medium-voltage, dry-type market. Four of the manufacturers produce liquid-immersed transformers, collectively representing more than 70 percent of the U.S. liquid-immersed market. The purpose of the interviews was to gather information about the financial impacts of standards on manufacturers, as well as the impacts of standards on employment and manufacturing capacity. The interviews provided valuable information that the Department used to evaluate the impacts of an energy conservation standard on manufacturers' cash flows, manufacturing capacities, and employment levels.

In addition to the six structured, detailed interviews, the Department conducted telephone interviews with four additional small businesses. The Department based the small-business interviews on an interview guide that was significantly different from that used for the structured, detailed interviews. Three of the small businesses interviewed produce medium-voltage, dry-type transformers, and one produces liquid-immersed transformers. Finally, in addition to the six detailed interviews and the four short telephone interviews with small businesses, the Department conducted telephone interviews with several companies that supply materials and equipment to the U.S. distribution transformer industry. The material and equipment suppliers included both U.S. firms and foreign suppliers. The Department visited one of the U.S. core steel suppliers. The following paragraphs describe more specifically the steps DOE took in developing the information on which the MIA was based.

2. Industry Profile

Phase 1 of the MIA consisted of preparing an industry profile. Before initiating the detailed impact studies, DOE collected information on the present and past structure and market characteristics of the distribution transformer industry. This activity involved both quantitative and qualitative efforts to assess the industry and equipment to be analyzed. The information collected included (1) manufacturer market shares, characteristics, and financial information; (2) product characteristics; and (3) trends in the number of firms, the market, and product characteristics.

The industry profile included a topdown cost analysis of the distribution transformer manufacturing industry that DOE used to derive cost and financial inputs for the GRIM, *e.g.*, revenues; material, labor, overhead, and depreciation costs; selling, general, and administrative (SG&A) expenses; and research and development (R&D) expenses. The Department used public sources of information to calibrate its initial characterization of the industry, including Securities and Exchange Commission (SEC) 10–K reports, corporate annual reports, the U.S. Census Bureau's Economic Census, Dun & Bradstreet reports, and industry analysis from Ibbotson Associates.

3. Industry Cash-Flow Analysis

Phase 2 of the MIA focused on the financial impacts of standards on the industry as a whole. The analytical tool DOE used for calculating the financial impacts of standards on manufacturers is the GRIM. In Phase 2, the Department used the GRIM to perform a preliminary industry cash-flow analysis. To perform this analysis, DOE used the financial values determined during Phase 1 and the shipment projections used in the NES analysis.

4. Subgroup Impact Analysis

In Phase 3 of the MIA, the Department established two distinct subgroups of distribution transformer manufacturers that could be affected by efficiency standards: Liquid-immersed and medium-voltage, dry-type. The Department also evaluated the impact of the energy conservation standards on small businesses. Small businesses, as defined by the Small Business Administration (SBA) for the distribution transformer manufacturing industry, are manufacturing enterprises with 750 or fewer employees.

5. Government Regulatory Impact Model Analysis

An energy conservation standard can affect a manufacturer's cash flow in three distinct ways: (1) It may require increased investment; (2) it may result in higher production costs per unit; and (3) it may alter revenue by virtue of higher per-unit prices and changes in sales volumes. As mentioned, the Department uses the GRIM to quantify the changes in cash flow that result in a higher or lower industry value. The GRIM analysis for this NOPR used a number of inputs—annual shipments; prices; material, labor, and overhead costs; SG&A expenses; taxes; and capital expenditures—to arrive at a series of annual net cash flows beginning in 2004 and continuing to 2038. The Department collected this information from a number of sources, including publicly available data; structured, detailed interviews with six manufacturers; and short telephone interviews with an additional four small manufacturers. The Department calculated INPV by discounting and summing the annual net cash flows. Chapter 12 of the TSD contains additional information about the GRIM analysis.

For the MIA, the Department considered two distinct markup scenarios: (1) The preservation-of-gross-margin-percentage scenario, and (2) the preservation-of-operating-profit scenario. Under the ''preservation-of-gross-margin-percentage'' scenario, DOE applied a single, uniform ''gross margin percentage'' markup across all efficiency levels. This scenario implies that, as production cost increases with efficiency, the absolute dollar markup will increase. The Department assumed that the non-production cost markup, which includes SG&A expenses, R&D expenses, interest, and profit, was 1.25. This markup is consistent with the one that the Department assumed in the engineering analysis and the base case of the GRIM.

The implicit assumption behind the ''preservation-of-operating-profit'' scenario is that the industry can maintain or preserve its operating profit (in absolute dollars) after the standard. The industry would do so by passing its increased costs on to its customers without increasing its operating profits in absolute dollars. The Department implemented this markup scenario in the GRIM by setting the non-production cost markups at each TSL to yield approximately the same operating profit in both the base case and the standard case in the year after standard implementation (2011).

The Department received several comments concerning the one-time expenditures that industry would incur in order to manufacture transformers that comply with energy conservation standards. The Department refers to such one-time expenditures as conversion capital expenditures and product conversion expenses, where the latter includes research, development, testing, and marketing expenditures related to achieving compliance. NEMA commented that the Department should contact individual manufacturers to learn about additional one-time conversion capital costs. (NEMA, No. 48 at p. 2) PEMCO Corporation made a similar comment, noting that mandatory energy conservation standards would cause small manufacturers to make new capital investments above and beyond those already made to improve transformer efficiency. (PEMCO, No. 57 at p. 1) Finally, ODOE urged the Department to consider the costs of transition to a standards-compliant industry. (ODOE, No. 66 at p. 3) The Department considers conversion capital expenditures, and also product conversion expenses, in setting energy conservation standards for any product, recognizes the importance of these issues to distribution transformer manufacturers, and explicitly considered such expenditures in its MIA. The Department gathered information pertaining to conversion expenditures by interviewing both transformer manufacturers and equipment suppliers to the distribution transformer industry.

EMSIC commented that investments will not cause a significant impact on manufacturers of liquid-immersed transformers if the energy conservation standard is set below a certain threshold. EMSIC asserted that liquid-immersed transformers can be made more efficient primarily by using better materials, without the need for significant investment. (EMSIC, No. 73 at p. 2) The Department concurs that conversion capital expenditures would be relatively modest for TSLs 1 through 4, which are the trial standard levels that would not involve partial or full conversion to amorphous core technology. TSLs 5 and 6 would require partial and full conversion to amorphous core technology, respectively, and the conversion capital expenditures necessary at these TSLs would be significant.

EMSIC commented that an energy conservation standard would positively affect liquid-immersed transformer manufacturer revenue (through higher prices), while also limiting product diversity and thereby dampening the cost increases at higher efficiencies. EMSIC suggested that one mechanism by which an energy conservation standard would limit product diversity would be the elimination of lower-grade materials. (EMSIC, No. 73 at p. 2) In the GRIM analysis, the Department explicitly considered the positive impact of standards on manufacturer revenue. While the Department recognizes that production cost increases in moving to higher TSLs could be dampened by limited product diversity, the Department believes that this effect will be small compared to the other effects explicitly considered in its analysis.

The final MIA-related comment received by the Department pertained to the Nation's import tariff on raw core steel. ZDMH is a mechanically scribed, deep-domain refined, core steel that survives the annealing process without negatively impacting the low loss properties of the steel. Since ZDMH core steel is available from only one foreign country, U.S. transformer manufacturers would have to purchase ZDMH subject to this tariff. This would give foreign transformer manufacturers that do not impose this tariff (*e.g.,* in Mexico) an advantage in producing transformers using ZDMH core steel, since finished cores or transformers would not be subject to the tariff. ERMCO asked the Department to keep this issue in mind when choosing the standard, to avoid putting domestic manufacturers at a disadvantage. (ERMCO, No. 58 at p. 2) The Department addressed the ZDMH issue in its engineering analysis by modeling Mexican-made transformers, because this would be the expected production scenario for ZDMH transformers. Since, according to the Department's analysis, ZDMH design option combinations would not be the most cost-effective at any trial standard level, DOE did not explicitly address the impact of the U.S. core steel tariff on transformer manufacturing capacity in the MIA. To review the cost-effectiveness findings of ZDMH in comparison to other transformer core steels, see TSD Chapter 5.

G. Employment Impact Analysis

The Process Rule includes employment impacts among the factors that DOE considers in selecting a proposed standard. Employment impacts include direct and indirect impacts. Direct employment impacts are any changes in the number of employees for distribution transformer manufacturers, their suppliers, and related service firms. Indirect impacts are those changes of employment in the larger economy that occur due to the shift in expenditures and capital investment that is caused by the purchase and operation of more efficient transformer equipment. The MIA addresses direct employment impacts; this section describes indirect impacts.

Indirect employment impacts from distribution transformer standards consist of the net jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, as a consequence of: (1) Reduced spending by end users on energy (electricity, gas—including liquefied petroleum gas—and oil); (2) reduced spending on new energy supply by the utility industry; (3) increased spending on the purchase price of new distribution transformers; and (4) the effects of those three factors throughout the economy. The Department expects the net monetary savings from standards to be redirected to other forms of economic activity. The Department also expects these shifts in spending and economic activity to affect the demand for labor.

In developing this proposed rule, the Department estimated indirect national employment impacts using an input/output model of the U.S. economy, called IMBUILD (impact of building energy efficiency programs). The Department's Office of Building Technology, State, and Community Programs (now the Building Technologies Program) developed the model. IMBUILD is a personal-computer-based, economic-analysis model that characterizes the interconnections among 35 sectors of the economy as national input/output structural matrices, using data from the U.S. Bureau of Labor Statistics. The IMBUILD model estimates changes in employment, industry output, and wage income in the overall U.S. economy resulting from changes in expenditures in the various sectors of the economy. The Department estimated changes in expenditures using the NES spreadsheet. IMBUILD then estimated the net national indirect employment impacts of potential distribution transformer efficiency standards on employment by sector.

While both the IMBUILD input/output model and the direct use of BLS employment data suggest the proposed distribution transformer standards could increase the net demand for labor in the economy, the gains would most likely be very small relative to total national employment. The Department therefore concludes only that the proposed distribution transformer standards are likely to produce employment benefits that are sufficient to offset fully any adverse impacts on employment in the distribution transformer or energy industries.

For more details on the employment impact analysis, *see* TSD Chapter 14. The Department did not receive stakeholder comments on these indirect employment impact methods, which it proposed in the ANOPR for use in the NOPR analysis.

H. Utility Impact Analysis

The proposed distribution transformer energy-efficiency standards have the distinct feature of regulating a product that also has electric utilities as one of the major product consumers. The Department therefore analyzed one portion of the impacts on utilities from the consumer perspective and another portion of impacts from the utility sector perspective. Those impacts that the Department analyzed in the utility impact analysis are from the utility sector perspective and include the impacts on the number of power plants constructed and the fuel consumption of the sector. Financial impacts on the utility sector are described in the LCC analysis.

The Department analyzed the effects of proposed standards on electric utility industry generation capacity and fuel consumption using a variant of the EIA's National Energy Modeling System (NEMS).[3] NEMS, which is available in the public domain, is a large, multi-sectoral, partial-equilibrium model of the U.S. energy sector. The EIA uses NEMS to produce its *Annual Energy Outlook*—a widely recognized baseline energy forecast for the U.S. The Department used a variant known as NEMS–BT.[4]

The Department conducted the utility analysis as policy deviations from the AEO2005, applying the same basic set of assumptions. The utility analysis reported the changes in installed capacity and generation, by fuel type, that result for each TSL, as well as changes in end-use electricity sales.

Details of the utility analysis methods and results are reported in TSD Chapter 13. The Department did not receive stakeholder comments on the utility impact analysis methods proposed in the ANOPR.

I. Environmental Analysis

The Department determined the environmental impacts of the proposed standards. Specifically, DOE calculated the reduction in power plant emissions of CO_2, sulfur dioxide (SO_2), NO_X , and mercury (Hg), using the NEMS–BT computer model. The environmental assessment published with the TSD, however, does not include the estimated reduction in power plant emissions of SO_2 because, as discussed below, any such reduction resulting from an efficiency standard would not affect the overall level of SO_2 emissions in the U.S. Like SO_2, future emissions of NO_X and Hg will be subject to emissions caps. The Department calculated a forecast of emissions reductions for these two types of emissions reductions, for emissions under an uncapped scenario. Under emissions-cap regulation, the Department assumes that the uncapped emissions reduction estimate corresponds to the generation of emissions allowance credits under an emissions-cap scenario.

The NEMS–BT is run similarly to the *AEO2005* NEMS, except that distribution transformer energy usage is reduced by the amount of energy (by fuel type) saved due to the trial standard levels. The Department obtained the input of energy savings from the NES spreadsheet. For the environmental analysis, the output is the forecasted physical emissions. The net benefit of the standard is the difference between emissions estimated by NEMS–BT and the *AEO2005* Reference Case.

The NEMS–BT tracks CO_2 emissions using a detailed module that provides robust results because of its broad coverage of all sectors and inclusion of interactive effects. In the case of SO_2, the Clean Air Act Amendments of 1990 set an emissions cap on all power generation. The attainment of this target, however, is flexible among generators and is enforced by applying market forces, through the use of emissions allowances and tradable permits. As a result, accurate simulation of SO_2 trading tends to imply that the effect of efficiency standards on physical emissions will be near zero because emissions will always be at, or near, the ceiling. Thus, there is virtually no real possible SO_2 environmental benefit from electricity savings as long as there is enforcement of the emissions ceilings. Though there may not be an actual reduction in SO_2 emissions from electricity savings, there still may be an economic benefit from reduced emissions demand. Electricity savings decrease the need to generate SO_2 emissions from power production, and consequently can decrease the need to purchase or generate SO_2 emissions allowance credits. This decreases the costs of complying with regulatory caps on emissions. *See* the environmental assessment, a separate report within the TSD, for a discussion of these issues.

Regarding the environmental assessment, ASAP stated that DOE should report other emissions impacts in addition to NO_X and CO_2, such as Hg and particulates. (Public Meeting Transcript, No. 56.12 at p. 247) The Department responded to this comment by adding Hg to the emissions reported in the environmental assessment. Particulates are a special case because they arise not only from direct emissions, but also from complex atmospheric chemical reactions that result from NO_X and SO_2 emissions. Because of the highly complex and uncertain relationship between particulate emissions and particulate concentrations that impact air quality, the Department did not report particulate emissions.

[3] For more information on NEMS, please refer to the U.S. Department of Energy, Energy Information Administration documentation. A useful summary is National Energy Modeling System: An Overview 2003, DOE/EIA–0581 (2003), March, 2003.

[4] DOE/EIA approves use of the name NEMS to describe only an official version of the model without any modification to code or data. Because this analysis entails some minor code modifications and the model is run under various policy scenarios that are variations on DOE/EIA assumptions, the Department refers to it by the name NEMS–BT (BT is DOE's Building Technologies Program, under whose aegis this work has been performed). NEMS–BT was previously called NEMS–BRS.

V. Analytical Results

A. Economic Justification and Energy Savings

1. Economic Impacts on Commercial Consumers

a. Life-Cycle Cost and Payback Period

The Department's LCC and PBP analyses provided five key outputs for each TSL that are reported in Tables V.1 through V.10 below. The first three outputs are the proportion of transformer purchases where the purchase of a standard-compliant design creates a net life-cycle cost, no impact, or a net life-cycle savings for the consumer. The fourth output is the average net life-cycle savings from a standard-compliant design. Finally, the fifth output is the average payback period for the consumer investment in a standard-compliant design. The payback period is the number of years it would take for the customer to recover, as a result of energy savings, the increased costs of higher-efficiency equipment, based on the operating cost savings from the first year of ownership. The payback period is an economic benefit-cost measure that uses benefits and costs without discounting. Detailed information on the LCC and PBP analyses can be found in TSD Chapter 8.

Table V.1 presents the summary of the LCC and PBP analysis for the representative unit from design line 1, a 50 kVA, liquid-immersed, single-phase, pad-mounted distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.97 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.56 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, and taxes) was $1,382.00.

TABLE V.1.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 1 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	98.9	98.9	98.9	99.04	99.19	99.59
Transformers with Net LCC Increase (%)	4.9	4.9	4.9	16.6	52.8	90.5
Transformers with No Change in LCC (%)	65.2	65.2	65.2	50.9	14.7	0.0
Transformers with Net LCC Savings (%)	29.9	29.9	29.9	32.5	32.5	9.5
Mean LCC Savings ($)	93	93	93	98	5	−688
Mean Payback Period (years)	11.4	11.4	11.4	21.9	36.0	45.0

Table V.2 presents the summary of the LCC and PBP analysis for the representative unit from design line 2, a 25 kVA, liquid-immersed, single-phase, pole-mounted distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.74 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.23 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, and taxes) was $737.00.

TABLE V.2.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 1 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	98.7	98.73	98.76	98.79	98.96	99.46
Transformers with Net LCC Increase (%)	1.4	3.0	5.2	8.6	43.9	98.9
Transformers with No Change in LCC (%)	66.6	64.3	60.8	56.3	25.4	0.0
Transformers with Net LCC Savings (%)	32.0	32.7	34.0	35.1	30.7	1.1
Mean LCC Savings ($)	69	70	72	71	7	−953
Mean Payback Period (years)	4.8	6.8	8.8	12.0	31.7	66.6

Table V.3 presents the summary of the LCC and PBP analysis for the representative unit from design line 3, a 500 kVA, liquid-immersed, single-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.36 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 99.07 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, and taxes) was $5,428.00.

TABLE V.3.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 3 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	99.3	99.38	99.46	99.54	99.74	99.75
Transformers with Net LCC Increase (%)	0.2	1.4	6.1	39.9	66.3	70.8

TABLE V.3.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 3 REPRESENTATIVE UNIT—Continued

	Trial standard level					
	1 TP 1	2	3	4	5	6
Transformers with No Change in LCC (%)	73.7	65.2	49.5	4.0	0.1	0.0
Transformers with Net LCC Savings (%)	26.1	33.4	44.4	56.1	33.6	29.2
Mean LCC Savings ($)	1,746	2,267	2,775	2,876	627	−410
Mean Payback Period (years)	1.4	4.3	10.4	19.8	29.3	32.3

Table V.4 presents the summary of the LCC and PBP analysis for the representative unit from design line 4, a 150 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.91 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.42 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, and taxes) was $3,335.00.

TABLE V.4.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 4 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	98.9	99.08	99.26	99.26	99.58	99.61
Transformers with Net LCC Increase (%)	3.3	16.8	41.0	41.0	64.4	75.5
Transformers with No Change in LCC (%)	63.7	40.8	11.3	11.3	0.8	0.0
Transformers with Net LCC Savings (%)	33.0	42.4	47.7	47.7	34.8	25.5
Mean LCC Savings ($)	556	629	450	450	56	−572
Mean Payback Period (years)	8.5	18.1	21.5	21.5	29.2	34.9

Table V.5 presents the summary of the LCC and PBP analysis for the representative unit from design line 5, a 1500 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.36 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 99.13 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, and taxes) was $11,931.00.

TABLE V.5.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 5 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	99.3	99.36	99.42	99.47	99.71	99.71
Transformers with Net LCC Increase (%)	0.3	1.5	10.2	15.9	57.1	57.2
Transformers with No Change in LCC (%)	71.7	62.8	40.0	24.2	0.0	0.1
Transformers with Net LCC Savings (%)	28.0	35.7	49.8	59.9	42.9	42.7
Mean LCC Savings ($)	3,957	5,463	6,504	7,089	4,431	3,902
Mean Payback Period (years)	3.4	6.1	12.7	14.1	25.6	26.1

Table V.6 presents the summary of the LCC and PBP analysis for the representative unit from design line 9, a 300 kVA, medium-voltage, dry-type, three-phase distribution transformer with a 45kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.77 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.41 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, contractor markup, and taxes) was $7,510.00.

TABLE V.6.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 9 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	98.6	98.82	99.04	99.26	99.41	99.41
Transformers with Net LCC Increase (%)	0.6	1.1	5.3	25.7	56.3	55.0

TABLE V.6.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 9 REPRESENTATIVE UNIT—Continued

	Trial standard level					
	1 TP 1	2	3	4	5	6
Transformers with No Change in LCC (%)	57.8	46.3	29.7	0.5	0.0	0.0
Transformers with Net LCC Savings (%)	41.6	52.6	65.0	73.8	43.7	45.0
Mean LCC Savings ($)	988	1,968	3,103	3,532	1,181	1,274
Mean Payback Period (years)	1.5	2.4	5.4	12.4	21.7	21.5

Table V.7 presents the summary of the LCC and PBP analysis for the representative unit from design line 10, a 1500 kVA, medium-voltage, dry-type, three-phase distribution transformer with a 45 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.17 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.79 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, contractor markup, and taxes) was $33,584.00.

TABLE V.7.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 10 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	99.1	99.20	99.30	99.39	99.51	99.51
Transformers with Net LCC Increase (%)	4.4	5.1	8.9	21.0	66.3	66.2
Transformers with No Change in LCC (%)	63.3	56.9	44.4	23.2	0.0	0.0
Transformers with Net LCC Savings (%)	32.3	37.6	46.7	55.8	33.7	33.8
Mean LCC Savings ($)	4,041	5,227	6,818	7,699	1,279	1,124
Mean Payback Period (years)	7.7	8.3	10.0	13.4	28.7	29.4

Table V.8 presents the summary of the LCC and PBP analysis for the representative unit from design line 11, a 300 kVA, medium-voltage, dry-type, three-phase distribution transformer with a 95 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.42 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.05 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, contractor markup, and taxes) was $10,945.00.

TABLE V.8.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 11 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	98.5	98.67	98.84	99.01	99.09	99.09
Transformers with Net LCC Increase (%)	2.4	3.9	9.8	22.0	34.2	33.2
Transformers with No Change in LCC (%)	42.5	34.6	18.7	2.3	0.0	0.0
Transformers with Net LCC Savings (%)	55.1	61.5	71.5	75.7	66.8	66.8
Mean LCC Savings Period ($)	2,491	3,621	4,313	4,845	4,186	4,289
Mean Payback (years)	3.8	4.9	7.9	11.8	15.1	14.8

Table V.9 presents the summary of the LCC and PBP analysis for the representative unit from design line 12, a 1500 kVA, medium-voltage, dry-type, three-phase distribution transformer with a 95 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.18 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.81 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, contractor markup, and taxes) was $33,590.00.

TABLE V.9.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 12 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	99.0	99.12	99.23	99.35	99.51	99.51
Transformers with Net LCC Increase (%)	1.4	1.5	5.8	18.2	70.6	70.1

TABLE V.9.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 12 REPRESENTATIVE UNIT—Continued

	Trial standard level					
	1 TP 1	2	3	4	5	6
Transformers with No Change in LCC (%)	75.1	71.9	56.9	28.2	0.0	0.0
Transformers with Net LCC Savings (%)	23.5	26.6	37.3	53.6	29.4	29.9
Mean LCC Savings ($)	2,600	3,973	5,485	6,812	−650	−655
Mean Payback Period (years)	4.6	4.7	8.3	12.7	29.3	29.3

Table V.10 presents the summary of the LCC and PBP analysis for the representative unit from design line 13, a 2000 kVA, medium-voltage, dry-type, three-phase distribution transformer with a 125 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.26 percent, the minimum efficiency of the baseline transformers selected during the LCC analysis was 98.97 percent, and the consumer equipment cost before installation (which includes manufacturer selling price, shipping costs, distributor markup, contractor markup, and taxes) was $41,873.00.

TABLE V.10.—SUMMARY LCC AND PBP RESULTS FOR DESIGN LINE 13 REPRESENTATIVE UNIT

	Trial standard level					
	1 TP 1	2	3	4	5	6
Efficiency (%)	99.0	99.15	99.30	99.45	99.55	99.55
Transformers with Net LCC Increase (%)	3.8	1.5	4.4	42.6	75.7	75.7
Transformers with No Change in LCC (%)	76.0	72.9	58.9	5.4	0.0	0.0
Transformers with Net LCC Savings (%)	20.2	25.6	36.7	52.0	24.3	24.3
Mean LCC Savings ($)	662	3,125	5,430	6,435	−5,303	−5,218
Mean Payback Period (years)	9.7	5.8	8.0	19.5	32.5	32.4

b. Rebuttable-Presumption Payback

As set forth in section 325(o)(2)(B)(iii) of EPCA, 42 U.S.C. 6295(o)(2)(B)(iii), there is a rebuttable presumption that an energy conservation standard is economically justified if the increased installed 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. However, while the Department examined the rebuttable-presumption criteria, the Department determined economic justification for the proposed standard levels through a more detailed analysis of the economic impacts of increased efficiency pursuant to section 325(o)(2)(B)(i) of EPCA. (42 U.S.C. 6295(o)(2)(B)(i))

The Department calculated a rebuttable-presumption payback period for each trial standard level, to determine if DOE could presume that a standard at that level is economically justified. Rather than using distributions for input values, DOE used discrete values and based the calculation on the DOE distribution-transformer-test-procedure assumptions. As a result, the Department calculated a single rebuttable-presumption payback value for each standard level, and not a distribution of payback periods.

To evaluate the rebuttable presumption, the Department estimated the additional cost of purchasing a more efficient, standard-compliant product, and compared this cost to the value of the energy savings during the first year of operation of the product as determined by the applicable test procedure. The Department interpreted the increased cost of purchasing a standard-compliant product to include the cost of installing the product for use by the purchaser. The Department then calculated the rebuttable-presumption payback period, or the ratio of the value of the first year's energy savings to the increase in purchase price. When the rebuttable-presumption payback period is less than three years, the rebuttable presumption is satisfied; when the payback period is equal to or more than three years, the rebuttable presumption is not satisfied.

The rebuttable-presumption payback period may differ from payback periods presented in other parts of this NOPR in at least two important ways:

- The rebuttable-presumption payback period uses test procedure loading levels to evaluate losses, rather than the Department's estimate of in-service loading conditions.
- Other payback periods may consider total operating costs, whereas the rebuttable-presumption payback period considers only the value of energy savings. In the case of distribution transformers, however, the Department estimates that the change in operating costs is solely due to energy savings.

There are three key inputs into the rebuttable-presumption payback calculation: (1) The average efficiency; (2) the average installed cost; and (3) the cost of electricity. Given the average efficiency of the baseline and standard-compliant transformers, the Department calculated the energy savings by taking the difference in the annual losses between the baseline and standard-compliant transformers, assuming the loading conditions from the test procedure. Multiplying the energy savings times the cost of electricity provided the value of the energy savings. Dividing the value of the energy savings into the installed-cost increase for a standard-compliant transformer provided the estimate of the rebuttable-presumption payback period. More detailed discussion on the rebuttable presumption is contained in TSD Chapter 8, section 8.7.

Table V.11 shows the rebuttable-presumption payback period as a function of design line and standard level.

TABLE V.11.—REBUTTABLE-PRESUMPTION PAYBACK IN YEARS

Design line	Rated capacity kVA	TSL1 (TP 1)	TSL2	TSL3	TSL4	TSL5	TSL6
1	50	7.0	7.0	7.0	10.1	16.0	27.2
2	25	2.1	3.6	4.3	5.2	15.2	42.4
3	500	0.5	2.2	5.1	9.7	22.7	25.1
4	150	3.9	7.4	12.0	12.0	17.2	20.7
5	1,500	2.6	4.5	6.5	9.0	20.0	20.0
9	300	0.7	1.3	2.5	5.6	11.3	11.3
10	1,500	3.2	3.8	4.8	6.1	12.4	12.4
11	300	2.0	2.6	3.8	5.3	7.0	7.0
12	1,500	2.3	2.5	3.3	5.3	13.6	13.6
13	2,000	5.0	3.3	4.1	8.2	16.7	16.7

c. Commercial Consumer Subgroup Analysis

In analyzing the potential impacts of new or amended standards, the Department evaluates impacts on identifiable groups (i.e., subgroups) of customers, such as different types of businesses, which may be disproportionately affected by a national standard. For this rulemaking, the Department identified rural electric cooperatives and municipal utilities as transformer consumer subgroups that could be disproportionately affected, and examined the impact of today's proposed standards on these groups.

The Department's analysis indicated that, for municipal utilities, the economics are similar to those of the national sample of utilities, but found significant differences in the results for rural cooperatives. Rural cooperatives have lower transformer loading levels than the average utility, and so their operating cost savings from higher standards would be smaller than those for the average utility. Chapter 11 of the TSD explains the Department's method for conducting the consumer subgroup analysis and presents the detailed results of that analysis.

Table V.12 shows the fraction of transformers that are impacted by different standard levels for the two commercial consumer subgroups. A transformer is impacted by a standard if the transformer design has to change in order to meet the performance requirements of the standard. Table V.13 shows the mean LCC savings from proposed energy-efficiency standards, and Table V.14 shows the mean payback period (in years) for the two commercial subgroups. Only the liquid-immersed design lines are included in this analysis since those types dominate the transformers purchased by electric utilities.

TABLE V.12.—FRACTION OF TRANSFORMERS PURCHASED BY COMMERCIAL CONSUMER SUBGROUPS IMPACTED BY ENERGY-EFFICIENCY STANDARDS

[Percent]

Design line	TSL1 (TP 1)	TSL2	TSL3	TSL4	TSL5	TSL6
Municipal Utility Subgroup						
1	35.3	35.3	35.3	48.6	84.8	100.0
2	33.9	34.7	39.3	44.1	74.9	100.0
3	26.1	35.2	50.4	96.0	99.9	100.0
4	35.9	60.2	88.3	88.3	99.2	100.0
5	27.9	36.0	59.1	75.6	99.9	99.9
Rural Cooperative Subgroup						
1	35.6	49.8	88.7	98.0	99.0	100.0
2	35.6	38.0	42.8	48.1	81.1	100.0
3	27.6	35.1	50.6	97.7	99.9	100.0
4	36.9	61.5	94.3	93.9	99.4	100.0
5	29.1	37.6	60.4	79.2	99.9	100.0

TABLE V.13.—MEAN LIFE-CYCLE COST SAVINGS FOR TRANSFORMERS PURCHASED BY COMMERCIAL CONSUMER SUBGROUPS

[Dollars]

Design line	Rated capacity kVA	TSL1 (TP 1)	TSL2	TSL3	TSL4	TSL5	TSL6
Municipal Utility Subgroup							
1	50	95	95	95	120	64	−594
2	25	69	66	70	73	17	−926
3	500	2,109	2,765	3,607	3,693	1,745	1,102

TABLE V.13.—MEAN LIFE-CYCLE COST SAVINGS FOR TRANSFORMERS PURCHASED BY COMMERCIAL CONSUMER SUBGROUPS—Continued

[Dollars]

Design line	Rated capacity kVA	TSL1 (TP 1)	TSL2	TSL3	TSL4	TSL5	TSL6
4	150	608	808	512	512	435	−165
5	1,500	4,853	6,649	8,128	9,013	7,680	7,453
Rural Cooperative Subgroup							
1	50	79	79	79	58	−91	−861
2	25	69	66	67	63	−25	−1,040
3	500	1,288	1,525	1,669	1,579	−1,630	−2,573
4	150	412	370	183	183	−599	−1,320
5	1,500	2,243	3,013	3,084	3,239	−3,617	−3,775

TABLE V.14.—MEAN PAYBACK PERIOD FOR TRANSFORMERS PURCHASED BY COMMERCIAL CONSUMER SUBGROUPS

[Years]

Design line	TSL1 (TP 1)	TSL2	TSL3	TSL4	TSL5	TSL6
Municipal Utility Subgroup						
1	11.1	11.1	11.1	19.9	33.2	43.0
2	4.8	7.0	8.8	12.0	30.6	65.4
3	1.2	3.8	8.7	19.2	27.4	29.9
4	7.7	15.0	21.5	21.5	27.1	32.5
5	2.9	5.1	11.0	12.9	23.7	23.7
Rural Cooperative Subgroup						
1	12.4	12.4	12.4	25.2	41.2	49.3
2	5.4	7.6	9.9	14.0	35.6	72.5
3	1.6	5.7	13.7	22.5	33.9	37.7
4	10.8	22.2	25.4	25.4	31.4	37.7
5	4.9	8.4	16.9	17.4	29.4	29.4

The LCC results for the municipal utilities subgroup are quite similar to the results for the national sample of utilities. Transformers purchased by municipal utilities tend to serve more diverse, urban loads than transformers that serve more rural areas. The increased load diversity increases the load factor and the transformer loading, thus increasing the potential savings from reduced load losses. Thus, compared to the other subgroup (rural cooperatives), the benefits from efficiency improvements are, on average, greater.

In contrast to the results for municipal utilities, the LCC savings tends to be lower for rural cooperatives, and the payback times tend to be longer. The LCC and PBP results for the rural cooperatives subgroup are mostly a reflection of the fact that the loading on rural transformers is lower, and thus the savings from reduced load losses are more modest. Distribution transformers purchased by rural cooperatives have lower loading than transformers that serve urban areas, primarily because the need to mitigate voltage flicker often results in the purchase of transformers of higher capacities, and because transformers purchased by rural cooperatives tend to serve isolated loads with lower load factors. The lower loading decreases the potential savings from reduced load losses, so the benefits from efficiency improvements are, on average, less than the municipal utility case per affected transformer.

2. Economic Impacts on Manufacturers

The Department performed an MIA to estimate the impact of higher efficiency standards on distribution transformer manufacturers. Chapter 12 of the TSD explains the methodology, analysis, and findings of this analysis in detail.

a. Industry Cash-Flow Analysis Results

Based on a real corporate discount rate of 8.9 percent, the Department estimated the distribution transformer industry impacts at each TSL. Table V.15 and Table V.16 show the estimated impacts for the liquid-immersed and medium-voltage, dry-type industries, respectively. The primary metric from the MIA is the change in INPV. These tables also present the investments that the industry would incur at each TSL. Product conversion expenses include engineering, prototyping, testing, and marketing expenses incurred by a manufacturer as it prepares to come into compliance with a standard. Capital investments are the one-time outlays for equipment and buildings required for the industry to come into compliance (i.e., conversion capital expenditures).

TABLE V.15.—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED INDUSTRY

	Units	Base case	Trial standard level					
			1	2	3	4	5	6
Preservation-of-Gross-Margin-Percentage Scenario								
INPV	($ millions)	526	532	537	553	561	549	552
Change in INPV	($ millions)		5.8	10.7	27.0	34.9	22.3	25.8
	(%)		1.1	2.0	5.1	6.6	4.2	4.9
Product Conversion Expenses.	($ millions)		0	0	0	0	109.2	161.2
Capital Investments	($ millions)		2.5	5.0	7.8	8.0	94.1	326.5
Total Investment Required	($ millions)		2.5	5.0	7.8	8.0	203.3	487.7
Preservation-of-Operating-Profit Scenario								
INPV	($ millions)	526	521	513	496	490	323	27
Change in INPV	($ millions)		−5.7	−12.9	−30.0	−36.9	−203.8	−499.6
	(%)		−1.1	−2.4	−5.7	−7.0	−38.7	−94.9
Product Conversion Expenses.	($ millions)		0	0	0	0	109.2	161.2
Capital Investments	($ millions)		2.5	5.0	7.8	8.0	94.1	326.5
Total Investment Required	($ millions)		2.5	5.0	7.8	8.0	203.3	487.7

TABLE V.16.—MANUFACTURER IMPACT ANALYSIS FOR MEDIUM-VOLTAGE, DRY-TYPE INDUSTRY

	Units	Base case	Trial standard level				
			1	2	3	4	5/6
Preservation-of-Gross-Margin-Percentage Scenario							
INPV	($ millions)	32	30	29	27	28	30
Change in INPV	($ millions)		−1.8	−3.3	−5.1	−3.8	−2.0
	(%)		−5.5	−10.1	−15.7	−11.8	−6.1
Product Conversion Expenses	($ millions)		0	0	3.3	3.6	5.0
Capital Investments	($ millions)		3.2	5.6	7.3	7.5	15.0
Total Investment Required	($ millions)		3.2	5.6	10.6	11.1	20.0
Preservation-of-Gross-Margin-Percentage Scenario							
INPV	($ millions)	32	30	28	25	24	15
Change in INPV	($ millions)		−2.5	−4.3	−6.9	−7.8	−17.0
	(%)		−7.7	−13.4	−21.5	−24.3	− 52.8
Product Conversion Expenses	($ millions)		0	0	3.3	3.6	5.0
Capital Investments	($ millions)		3.2	5.6	7.3	7.5	15.0
Total Investment Required	($ millions)		3.2	5.6	10.6	11.1	20.0

b. Impacts on Employment

The Department expects no significant, discernable direct employment impacts among liquid-immersed transformer manufacturers under TSL1 through TSL4, but potentially large increases in employment for TSL5 and TSL6 (35 percent and 99 percent, respectively). These conclusions—which are separate from any conclusions regarding employment impacts on the broader U.S. economy—are based on modeling results that address neither the possible relocation of domestic transformer manufacturing employment to lower labor-cost countries, nor the possibility of outsourcing amorphous core production under TSL5 and TSL6 to companies in other countries. The Department discussed this scenario of outsourcing amorphous core production to other countries during several liquid-immersed manufacturer interviews, and it appears that outsourcing would be a serious consideration for the liquid-immersed industry under TSL5 or TSL6.

Liquid-immersed manufacturers expressed concern during the MIA interviews that establishing an energy conservation standard would ‘‘commoditize’’ the liquid-immersed transformer market, making it easier for foreign manufacturers who specialize in low-cost mass production of one design to enter the U.S. market. If foreign producers were to capture significant market share, U.S. transformer-manufacturing employment would be negatively affected. As a point related to ‘‘commoditization,’’ but separate from employment impacts, manufacturers also warned the Department about a potential backsliding effect, whereby the average efficiency of liquid-immersed transformers could potentially decrease under standards, since transformer customers may stop evaluating and instead simply purchase minimally compliant designs. Manufacturers reported having observed such a backsliding phenomenon in customer orders from Massachusetts, where TP1 is a mandatory standard.

The Department expects no significant, discernable employment impacts among medium-voltage, dry-type transformer manufacturers for any TSL compared to the base case. The Department's conclusion regarding employment impacts in the medium-voltage, dry-type transformer industry is separate from any conclusions regarding employment impacts on the broader U.S. economy. Increased employment levels are not expected at higher TSLs because the core-cutting equipment typically purchased by the medium-voltage, dry-type industry is highly automated and includes core-stacking equipment.

Another concern conveyed by some medium-voltage, dry-type manufacturers during the interviews is the potential impact stemming from the cast-coil transformer competitiveness at higher TSLs. These manufacturers claim that setting a standard above a certain threshold may trigger a market switch from open-wound ventilated transformers to cast-coil transformers. Manufacturers suggest that this crossover point likely occurs at TSL3 and higher. If the market does shift to cast-coil transformers, there is a risk of imported pre-fabricated cast coils dominating the market in the long term. This would have a significant impact on domestic industry value and domestic employment in the medium-voltage, dry-type industry.

c. Impacts on Manufacturing Capacity

For the liquid-immersed distribution transformer industry, the Department believes that there are only minor production capacity implications for a standard at TSL4 and below. At TSL6, all liquid-immersed design lines would have to convert to amorphous technology, the most efficient core material. At TSL5, three design lines would have to convert to amorphous core designs. Conversion to amorphous core designs would render obsolete a large portion of the equipment used in the liquid-immersed industry today (e.g., annealing furnaces, core-cutting and winding equipment). Based on the manufacturer interviews, DOE believes that TSL5 and TSL6 would cause liquid-immersed transformer manufacturers to decide whether they would tool for amorphous technology, attempt to purchase pre-fabricated amorphous cores, or exit the industry. Manufacturers also indicated that, if they were to choose to produce amorphous cores themselves, they would face a critical decision about whether or not to relocate outside of the U.S., since much of their equipment would become obsolete. As mentioned above, if manufacturers choose to purchase pre-fabricated amorphous cores, they might purchase them from foreign manufacturers.

Energy conservation standards will affect the medium-voltage, dry-type industry's manufacturing capacity because the core stack heights (or core steel piece length) will increase and laminations will become thinner. Thinner laminations require more cuts and are more cumbersome to handle. Therefore, manufacturers would have to invest in additional core-mitering machinery or modifications and improvements to recover any losses in productivity, and these factors might also contribute to a need for more plant floor space. Because more-efficient transformers tend to be larger, this could also contribute to the need for additional manufacturing floor space.

d. Impacts on Manufacturers That Are Small Businesses

Converting from a company's current basic product line involves designing, prototyping, testing, and manufacturing a new product. These tasks have associated capital investments and product conversion expenses. Small businesses, because of their limited access to capital and their need to spread conversion costs over smaller production volumes, may be affected more negatively than major manufacturers by an energy conservation standard. For these reasons, the Department specifically evaluated the impacts on small businesses of an energy conservation standard.

The Small Business Administration defines a small business, for the distribution transformer industry, as a business that has 750 or fewer employees. The Department estimates that, of the approximately 25 U.S. manufacturers that make liquid-immersed distribution transformers, about 15 of them are small businesses. About five of the small liquid-immersed transformer businesses have fewer than 100 employees. The liquid-immersed distribution transformer industry largely produces customized transformers. Often, small businesses can compete in this industry because a typical customer order can involve unique designs produced in relatively small volumes. Small manufacturers in the liquid-immersed industry tend not to compete on the higher-volume products and often produce transformers for highly specific applications. This strategy allows small manufacturers in the liquid-immersed transformer industry to be competitive in certain product markets. Implementation of an energy conservation standard would have a relatively minor differential impact on small manufacturers (versus large manufacturers) of liquid-immersed distribution transformers. Disadvantages to small businesses, such as having little leverage over suppliers (e.g., core steel suppliers), are present with or without an energy conservation standard.

For medium-voltage, dry-type manufacturers, the situation is different. The Department estimates that, of the 25 U.S. manufacturers that make medium-voltage, dry-type distribution transformers, about 20 of them are small businesses. About one-half of the medium-voltage, dry-type small businesses have fewer than 100 employees. Medium-voltage, dry-type transformer manufacturing is more concentrated than liquid-immersed transformer manufacturing; the top three companies manufacture over 75 percent of all transformers in this category. The entire medium-voltage, dry-type transformer industry has such low shipments that no designs are produced at high volume. There is little repeatability of designs, so small businesses can competitively produce many medium-voltage, dry-type, open-wound designs. The medium-voltage, dry-type industry as a whole primarily has experience producing baseline transformers and transformers that would comply with TSL1. In addition, the industry produces a significant number of units that would comply with TSL2, but approximately one percent or less of the market would comply with TSL3 or higher (today). Therefore, all manufacturers, including small businesses, would have to develop designs to enable compliance with TSL3 or higher. For these small manufacturers, the R&D costs would be more burdensome, as product redesign costs tend to be fixed and do not scale with sales volume. Thus, small businesses would be at a relative disadvantage at TSL3 and higher, because their R&D efforts would be on the same scale as those for larger companies, but these expenses would be recouped over smaller sales volumes.

At TSL3 and above, DOE estimates that net cash flows for the medium-voltage, dry-type industry would go negative during the compliance period. At these TSLs, the impacts on the industry as a whole are large and affect businesses of all sizes, but there would be some differential, increased impacts on small businesses. For example, at TSL3 and above, the use of grain-oriented silicon steel of M3 grade would be necessary. Cutting M3 core steel on the core-mitering equipment typically purchased by smaller businesses can be problematic because of the thinness of the material.

At TSL2, all medium-voltage, dry-type designs would have to be mitered. (Mitering means the transformer core's joints intersect at 45 degree angles, rather than at 90 degree angles as is true for ''butt-lap'' designs; buttlap designs are less energy efficient.) The mitered core construction technique could constrain the core-mitering resources of small businesses that share core-cutting capacity with production lines for other transformers that are not covered by this rulemaking (e.g., low-voltage, dry-type distribution transformers). At TSL1, many kVA ratings could still be constructed using butt-lap joints, alleviating the constraint on core-mitering resources. Thus, TSL1 is less capital-intensive for small businesses than TSL2 (large businesses would likely miter nearly all medium-voltage cores, even at TSL1). In the medium-voltage, dry-type transformer industry, which is heavily consolidated already, there is the risk that TSL2 could lead to further advantage for the largest manufacturers and thus further concentrate the industry's production.

3. National Impact Analysis

a. Amount and Significance of Energy Savings

The Department estimated the energy savings from a proposed energy-efficiency standard in its NES analysis. The amount of energy savings depends not only on the potential decrease in transformer losses due to a standard, but also on the rate at which the stock of existing, less efficient transformers will be replaced over time after the implementation of a proposed energy-efficiency standard.

Another factor that affects national energy savings estimates is the efficiency of the power plants and the transmission and distribution system that supplies electricity to transformers. The factor that relates energy savings at the transformer to fuel savings at the power plant is the site-to-source conversion factor. The NES analysis takes as an input estimates of the energy savings per transformer resulting from proposed energy-efficiency standards that are calculated in the LCC model. The NES model then accounts for transformer stock replacement and site-to-source energy conversion to estimate annual national energy savings through an extended forecast period ending in 2038. The replacement of existing transformer stocks by new, more efficient transformers is described by the Department's shipments model, described in TSD Chapter 9. The Department calculated the site-to-source conversion factor that relates transformer loss reduction to fuel savings at the power plant using NEMS–BT, a variant of the EIA's NEMS, which is described in TSD Chapter 13 (Utility Impact Analysis).

Table V.17 summarizes the Department's NES estimates, which are described in more detail in TSD Chapter 10. The Department reports both undiscounted and discounted values of energy savings. The undiscounted energy savings estimates increase steadily from 1.77 to 9.77 quads for TSLs 1 through 6, where there are increasing energy savings as the standard level increases. Discounted energy savings represent a policy perspective where energy savings farther in the future are less significant than energy savings closer to the present. The discounted energy savings estimates are approximately one half and one fourth of the undiscounted values for the three- and seven-percent discount rates, respectively.

b. Energy Savings and Net Present Value

While the NES provides estimates of the energy savings from a proposed energy-efficiency standard, the NPV provides estimates of the national economic impacts of a proposed standard. The NPV calculation for this rulemaking used first-cost data from the LCC analysis to estimate the equipment and installation costs associated with purchase and installation of higher efficiency transformers. The LCC analysis also provided the marginal electricity cost data that the Department used to estimate the economic value of energy savings associated with lower transformer losses.

One key factor in the NPV calculation that was not obtained from the LCC analysis is the discount rate. The Department discounted transformer purchase costs, installation expenses, and operating costs using a national average discount rate for policy evaluation that the Department determined consistent with Office of Management and Budget (OMB) guidance.

In accordance with the OMB guidelines on regulatory analysis (OMB Circular A–4, section E, September 17, 2003), DOE calculated NPV using both a seven-percent and a three-percent real discount rate. The seven-percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy, and reflects returns to real estate and small business capital as well as corporate capital. The Department used this discount rate to approximate the opportunity cost of capital in the private sector, since recent OMB analysis has found the average rate of return to capital to be near this rate. In addition, DOE used the three-percent rate to capture the potential effects of standards on private consumption (e.g., through higher prices for equipment and purchase of reduced amounts 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 (e.g., yield on Treasury notes minus annual rate of change in the Consumer Price Index), which has averaged about three percent on a pre-tax basis for the last 30 years. Table V.17 provides an overview of the NES and NPV results. See TSD Chapter 10 for more detailed NES and NPV results.

TABLE V.17.—TSL RESULTS SUMMARY: NATIONAL ENERGY SAVINGS (QUADS, 2010–2038) AND NET PRESENT VALUE

[Billion 2004$, at 3% and 7% discount rates, 2010–2073]

	TSL1 (TP 1)	TSL2	TSL3	TSL4	TSL5	TSL6
Sum of all Product Classes						
Energy Savings (quads)	1.77	2.39	3.15	3.63	6.90	9.77
Discounted Energy Savings (quads):						
3%	0.90	1.21	1.58	1.82	3.47	4.91
7%	0.40	0.54	0.71	0.82	1.54	2.19
NPV (billion 2004$):						
3%	7.43	9.43	10.11	11.07	10.88	−9.41
7%	2.15	2.52	2.28	2.26	−1.13	−14.09

c. Impacts on Employment

The Process Rule includes employment impacts among the factors DOE considers in selecting a proposed standard. Employment impacts include direct and indirect impacts. Direct employment impacts are any changes in the number of employees for distribution transformer manufacturers. Indirect impacts are those changes of employment in the larger economy that occur due to the shift in expenditures and capital investment that is caused by the purchase and operation of more efficient equipment. The MIA addresses direct employment impacts; this section describes indirect impacts.

In developing this proposed rule, the Department estimated indirect national employment impacts using an input/output model of the U.S. economy, called IMBUILD (impact of building energy efficiency programs). Indirect employment impacts from distribution transformer standards consist of the net jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, as a consequence of: (1) Reduced spending by end users on energy (electricity, gas—including liquefied petroleum gas—and oil); (2) reduced spending on new energy supply by the utility industry; (3) increased spending on the purchase price of new distribution transformers; and (4) the effects of those three factors throughout the economy. The Department expects the net monetary savings from standards to be redirected to other forms of economic activity. The Department also expects these shifts in spending and economic activity to affect the demand for labor.

As shown in table V.18, the Department estimates that net indirect employment impacts from a proposed transformer energy-efficiency standard are positive. According to the Department's analysis, the number of jobs that may be generated through indirect impacts ranged from 5,000 to 20,000 by 2038 for the proposed standard levels of TSL1 through TSL6 respectively. For shorter forecast periods, indirect employment impacts are correspondingly smaller. While the Department's analysis suggests that the proposed distribution transformer standards could increase the net demand for labor in the economy, the gains would most likely be very small relative to total national employment. The Department therefore concludes only that the proposed distribution transformer standards are likely to produce employment benefits that are sufficient to offset fully any adverse impacts on employment that might occur in the distribution transformer or energy industries. For details on the employment impact analysis methods and results, see TSD Chapter 14.

TABLE V.18.—NET NATIONAL CHANGE IN INDIRECT EMPLOYMENT, THOUSANDS OF JOBS IN 2038

	Trial standard level					
	TSL1	TSL2	TSL3	TSL4	TSL5	TSL6
Liquid-Immersed	4.7	6.4	7.7	8.7	18.2	19.4
Dry-Type, Medium-Voltage	0.3	0.5	0.7	1.0	1.4	1.4

4. Impact on Utility or Performance of Equipment

In establishing classes of products, and in evaluating design options and the impact of potential standard levels, the Department has tried to avoid having new standards for distribution transformers lessen the utility or performance of these products (see TSD Chapter 7, section 7.3.1). The proposed standard level (TSL2) does not lessen the performance of any of the distribution transformers being regulated.

The standard level could, however, potentially affect utility through the larger size and weight of an energy-efficient distribution transformer. The Department accounted for dimensionally or physically constrained transformers in its LCC model by including the cost of dealing with physical constraints in the installation cost estimate. For all types of transformers, the Department included extra labor and equipment costs that may be incurred in the installation of larger, heavier, more efficient transformers. Design line 2 includes pole-mounted transformers and presents a special case because of the extra cost of installing or replacing electrical distribution poles on which such transformers may be mounted by utilities. For single-phase, pole-mounted, liquid-immersed transformers, the LCC spreadsheet model includes an estimate of the additional installation costs for those designs that would require an upgrade to the pole (see TSD Chapter 7, section 7.3.1). Having accounted for this constraint on utility in its economic model, the Department concludes that TSL2 does not reduce the utility or performance of distribution transformers.

5. Impact of Any Lessening of Competition

The Department considers any lessening of competition that is likely to result from 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, not later than 60 days after the publication of a proposed rule, together with an analysis of the nature and extent of such impact. (See 42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii)).

To assist the Attorney General in making such a determination, the Department has provided the Department of Justice (DOJ) with copies of this notice and the TSD for review. At DOE's request, the DOJ reviewed the MIA interview questionnaire to ensure that it would provide insight concerning any lessening of competition due to any proposed TSLs.

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. The energy savings from distribution transformer standards result in reduced emissions of CO_2, and reduced power sector demand for NO_X, and Hg emissions reduction investments. Reduced electricity demand from energy-efficiency 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 this reduced demand, the Department expects the proposed standard to eliminate the need for the construction of approximately 11 new 400-megawatt power plants by 2038 and to save 2.39 quads of electricity (cumulative, 2010–2038).

Table V.19 provides the Department's estimate of cumulative CO_2, NO_X, and Hg emissions reductions for an uncapped emissions scenario for the six

TSLs considered in this rulemaking. In actuality, present and/or future regulations will place caps on the emissions of NO_X, and Hg for the power sector, and thus the emissions reductions provided in the table represent the Department's estimate of the potential reduced demand for emissions reduction investments in future cap and trade emissions markets. The expected energy savings from distribution transformer standards will reduce the emissions of greenhouse gases associated with energy production and household use of fossil fuels, and it may reduce the cost of maintaining system-wide emissions standards and constraints.

TABLE V.19.—CUMULATIVE EMISSIONS REDUCTIONS FROM TRIAL STANDARD LEVELS BY PRODUCT TYPE, 2010–2038

	Trial standard level					
	TSL1	TSL2	TSL3	TSL4	TSL5	TSL6
Emissions reductions for liquid-immersed transformers:						
CO_2 (Mt)	117.4	158.2	205.4	232.8	451.2	647.6
NO_X (kt)	31.7	42.7	55.5	62.8	121.7	174.8
Hg (t)	2.9	3.5	4.1	4.5	5.8	5.9
Emissions reductions for medium-voltage, dry-type transformers:						
CO_2 (Mt)	5.6	8.9	12.8	19.5	31.2	31.2
NO_X (kt)	2.3	3.7	5.3	8.1	12.9	12.9
Hg (t)	0.10	0.17	0.24	0.36	0.58	0.58

The cumulative CO_2, NO_X, and Hg emissions reductions range up to 678.8 Mt, 187.7 kt, and 6.48 t, respectively, in 2038 (sum of liquid-immersed and medium-voltage dry-type at TSL6). Total CO_2 and NO_X emissions reductions for each TSL are reported in the environmental assessment, a separate report in the TSD.

In the ANOPR, the Department stated that, for its NOPR analysis, it would calculate discounted values for future emissions. 69 FR 45376. Accordingly, the Department here presents its results for discounted emissions of CO_2 and NO_X. When NO_X emissions are subject to emissions caps, the Department's emissions reduction estimate corresponds to incremental changes in emissions allowance credits in cap and trade emissions markets rather than the net physical emissions reductions that will occur. The Department used the same discount rates that it used in calculating the NPV (seven percent and three percent real) to calculate discounted cumulative emission reductions. Table V.20 shows the discounted cumulative emissions impacts for both liquid-immersed and dry-type, medium-voltage transformers.

The seven-percent and three-percent real discount rate values are meant to capture the present value of costs and benefits associated with projects facing an average degree of risk. Other discount rates may be more applicable to discount costs and benefits associated with projects facing different risks and uncertainties. The Department seeks input from interested parties on the appropriateness of using other discount rates in addition to seven percent and three percent real to discount future emissions reductions.

TABLE V.20.—DISCOUNTED CUMULATIVE EMISSIONS REDUCTIONS, LIQUID-IMMERSED AND DRY-TYPE, MEDIUM-VOLTAGE TRANSFORMERS, 2010–2038

	Discounted cumulative emissions reduction					
	TSL 1 (TP 1)	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
Liquid-Immersed, 3% discount, CO_2 (Mt)	58.2	78.4	101.9	115.5	223.5	321.1
Dry-Type, 3% discount, CO_2 (Mt)	2.8	4.4	6.4	9.7	15.5	15.5
Liquid-Immersed, 7% discount, CO_2 (Mt)	25.3	34.0	44.3	50.1	96.9	139.4
Dry-Type, 7% discount, CO_2 (Mt)	1.2	1.9	2.8	4.2	6.7	6.7
Liquid-Immersed, 3% discount, NO_X (kt)	16.3	21.9	28.6	32.4	62.6	90.0
Dry-Type, 3% discount, NO_X (kt)	1.2	1.8	2.7	4.0	6.5	6.5
Liquid-Immersed, 7% discount, NO_X (kt)	7.5	10.1	13.2	15.0	28.9	41.6
Dry-Type, 7% discount, NO_X (kt)	0.5	0.8	1.2	1.8	2.9	2.9

7. Other Factors

The Secretary of Energy, in determining whether a standard is economically justified, considers any other factors that the Secretary deems to be relevant. (See 42 U.S.C. 6295(o)(2)(B)(i)(VII)) For today's proposed standard, the Secretary took into consideration transformer-manufacturing-material price volatility—a factor that received several comments at the ANOPR public meeting, during the comment period following the meeting, and in the MIA interviews. Stakeholders expressed concern about the increasing cost of raw materials for building transformers, the volatility of material prices, and the cumulative effect of material price increases on the transformer industry (see section IV.B.2, Engineering Analysis Inputs). The Department conducted supplemental engineering and LCC analyses using first-quarter 2005 material prices, and considered the impacts on LCC savings and payback periods when evaluating the appropriate standard levels for liquid-immersed and medium-voltage, dry-type distribution transformers. The results of the engineering and LCC analyses for the first-quarter 2005 material price analysis are in the TSD Appendix 5C.

B. Stakeholder Comments on the Selection of a Final Standard

During the public comment period on the ANOPR, the Department received numerous comments from stakeholders relating to the selection of the appropriate standard level for distribution transformers. Stakeholders expressed a range of opinions on what efficiency levels the Department should select for a standard, some relating specifically to liquid-immersed transformers and others to both liquid-immersed and medium-voltage, dry-type units.

Concerning liquid-immersed distribution transformers, Cooper Industries recommended that NEMA TP 1 be adopted for design lines 1, 2, and 4. For design lines 3 and 5, Cooper recommended CSL2, which is one level higher than the TP 1 level. (Note that for the ANOPR, the CSLs were slightly different from the levels considered for the NOPR; for the ANOPR, CSL2 for design line 3 was 99.40 percent and CSL2 for design line 5 was 99.40 percent.) For design line 5, Cooper stated that the majority of users are industrial customers, who would typically require the value of annual energy savings resulting from efficiency level increases to pay back the cost of those increases in two to four years, or provide a 15 to 30 percent annual rate of return on such cost. (Cooper, No. 62 at pp. 4–6) EMSIC commented that mandatory efficiency standards can be set at TP 1 + 0.4 percent for all liquid-immersed products without undue burden on any stakeholders. (EMSIC, No. 73 at p. 2) The Department considered these comments from Cooper Industries and EMSIC while reviewing the analytical results and selecting a proposed standard level for liquid-immersed distribution transformers.

Howard stated that it does not believe the Department should establish mandatory efficiency standards for liquid-immersed distribution transformers because, through TOC evaluation, the market already drives these transformers to cost-effective efficiency levels. Howard participates in the Energy Star program, and believes the Department should take a voluntary approach to standards. (Howard, No. 70 at p. 2) As discussed earlier in this notice, the Department is charged with determining whether standards for distribution transformers are technologically feasible and economically justified and would result in significant energy savings. (42 U.S.C. 6317(a)) Based on the analysis and information available to date, it appears that standards for liquid-immersed distribution transformers would be technologically feasible and economically justified, and would result in significant energy savings. Thus, the Department will continue to evaluate minimum efficiency standards for liquid-immersed transformers.

Howard continued by stating that if DOE must mandate efficiency levels for liquid-immersed transformers, then it recommends the Department use specific efficiency levels provided in its comment. For single-phase transformers, the levels proposed by Howard start at 98.8 percent for 10 kVA transformers and rise to 99.4 percent for 75 kVA transformers, above which the proposed level is constant. For three-phase transformers, the levels proposed by Howard start at 98.5 percent for 15 kVA transformers and rise to 99.4 percent for 225 kVA transformers, above which the proposed level is constant. (Howard, No. 70 at pp. 3 and 5) The Department considered these recommended levels from Howard while reviewing the analytical results and selecting a proposed standard level for liquid-immersed distribution transformers.

The Department also received several cross-cutting comments that pertained to the appropriate standard level for all product classes being evaluated. HVOLT, NGrid, and Southern provided comments in support of NEMA TP 1. HVOLT stated that, based on its involvement in the development of NEMA TP 1, it recommends setting the new DOE standard at NEMA TP 1 levels, which have a 3–5-year payback period at the nationwide average cost of energy. It noted that this level would guarantee wide support for the standard. (HVOLT, No. 65 at p. 3) NGrid stated that a standard that encourages utilities to install transformers that meet the efficiency levels outlined in NEMA TP 1–1996 is in the best interests of the company and its customers. (NGrid, No. 80 at p. 2) Similarly, Southern Company commented that the minimum efficiency standard should be no higher than NEMA TP 1. It added that the choice of transformers with efficiencies higher than TP 1 should be left to the customer. (Southern, No. 71 at p. 3) The Department included TP 1 in its analysis but determined that a higher efficiency level was economically justified for the liquid-immersed and medium-voltage, dry-type super classes, and would result in significant energy savings.

EEI and NRECA commented that the Department should select a standard level based on the percentage of transformer consumers with positive LCC savings, and that the standard should result in net positive LCC savings for at least 90 percent of affected consumers. (EEI, No. 63 at p. 3; NRECA, No. 74 at p. 2) The Department considered the percentage of transformer users with positive LCC savings in identifying the proposed standard level but not did set a specific threshold for users with positive LCC savings. Discussion of this and other factors DOE considered in selecting the proposed standard level appears in section V.C of this notice.

The Department also received comments encouraging consideration of standard levels higher than TP 1. ASE recommended that efficiency standard levels be set at the levels with maximum LCC savings. (ASE, No. 52 at p. 4 and No. 75 at p. 4) LCC savings is one of several criteria EPCA considers when determining whether a standard is economically justified, and therefore it is one of the criteria the Department used to select today's proposed standard level.

CDA stated that the standard level should be set at higher efficiencies than TP 1 because actual loading exceeds the 35 percent and 50 percent loading assumptions used in the TP 1 analysis. (CDA, No. 69 at p. 3) CDA urged the Department to set a minimum efficiency level that represents a challenge to the industry, beyond a minimal standard that all can achieve. It noted that it does not believe TP 1 is challenging enough to transformer manufacturers. (CDA, No. 51 at p. 4 and No. 69 at p. 4) The Department selected the highest efficiency level that its analysis identified as justified under EPCA's criteria. The selected standard will impact the industry, but the Department did not specifically use ''industry challenge'' as a decision criterion.

Today's proposed standard is not based on any one factor or criterion as some commenters suggested. Rather, the Department arrived at its decision by weighing the costs and benefits of the trial standard levels using the seven factors described in section II.B of this notice. The proposed standard is set at the highest level that is technologically feasible and economically justified (and would result in significant energy savings).

C. Proposed Standard

The Department evaluated whether its TSLs for distribution transformers achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified (and would result in significant energy savings). In determining whether a standard is economically justified, DOE determines whether the benefits of the standard exceed its costs. Any new or amended standard for distribution transformers must result in significant energy savings.

In selecting a proposed energy conservation standard for distribution transformers, the Department followed its normal approach. It started by comparing the maximum technologically feasible level with the base case, and determined whether that level was economically justified. Upon finding the maximum technologically feasible level not to be justified, the Department analyzed the next lower TSL to determine whether that level was economically justified. The Department repeated this procedure until it identified a TSL that was economically justified. The Department made its determination of economic justification on the basis of the NOPR analysis results published today and the comments that were submitted by stakeholders. Beginning with the most efficient level, this section discusses each TSL for liquid-immersed transformers and then each TSL for medium-voltage, dry-type transformers.

The following two tables summarize DOE's analytical results. They will aid the reader in the discussion of costs and benefits of each TSL. Each table presents the results or, in some cases, a range of results, for the underlying design lines for liquid-immersed (Table V.21) and medium-voltage, dry-type (Table V.22) distribution transformers. The range of values reported in these tables for LCC, payback, and average increase in consumer equipment cost before installation encompass the range of results calculated for either the liquid-immersed or medium-voltage, dry-type representative units. The range of values for the manufacturer impact represents the results for the preservation-of-operating-profit scenario and preservation-of-gross-margin scenario at each TSL for liquid-immersed and medium-voltage, dry-type transformers.

TABLE V.21.—SUMMARY OF LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS ANALYTICAL RESULTS

Criteria	Trial standard level					
	TSL1	TSL2	TSL3	TSL4	TSL5	TSL6
Energy saved (quads)	1.70	2.28	2.99	3.38	6.51	9.38
Generation Capacity Offset (GW)	3.1	4.3	5.5	6.2	12.1	17.3
Discounted energy saved, 7% (quads)	0.38	0.51	0.67	0.76	1.45	2.10
NPV ($ billions):						
@ 7% discount	2.02	2.31	2.01	1.92	(1.14)	(14.10)
@ 3% discount	7.02	8.78	9.20	9.83	9.94	(10.31)
Emission reductions:						
CO_2 (Mt)	117.4	158.2	205.4	232.8	451.2	647.6
NO_X (kt)	31.7	42.7	55.5	62.8	121.7	174.8
Life-Cycle Cost:						
Net Savings (%)	26.1–32.0	32.5–42.4	32.5–49.8	35.1–67.7	30.7–42.9	1.1–42.7
Net Increase (%)	0.2–4.9	1.4–16.8	5.2–52.8	8.6–39.9	43.9–66.3	57.2–98.9
No Change (%)	63.7–73.7	40.8–65.2	11.3–60.8	4.0–56.3	0.0–25.4	0.0–0.1
Payback (years)	1.4–11.4	4.3–18.1	8.8–21.5	12.0–21.9	25.6–36.0	25.6–67
Average increase in consumer equipment cost before installation (%) * †	1.4–4.2	2.7–12.8	3.0–38.3	4.2–40.6	15.5–141.9	106.9–160
Manufacturer Impact:						
INPV ($ millions)	(5.7)–5.8	(12.9)–10.7	(30.0)–27.0	(36.9)–34.9	(203.8)–22.3	(499.6)–25.8
INPV change (%)	(1.1)–1.1	(2.4)–2.0	(5.7)–5.1	(7.0)–6.6	(38.7)–4.2	(94.9)–4.9

* Percent increase in consumer equipment cost before installation, five-year average material pricing.
† The Department recognizes that these cost changes are the average changes for the Nation, and that some individual customers will experience larger changes, particularly if these customers are not evaluating losses when purchasing transformers.

TABLE V.22.—SUMMARY OF MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS ANALYTICAL RESULTS

Criteria	Trial standard level					
	TSL1	TSL2	TSL3	TSL4	TSL5	TSL6
Energy saved (quads)	0.07	0.11	0.16	0.25	0.39	0.39
Generation Capacity Offset (GW)	0.1	0.2	0.3	0.4	0.6	0.6
Discounted energy saved, 7% (quads)	0.02	0.03	0.04	0.06	0.09	0.09
NPV ($ billions):						
@ 7% discount	0.13	0.21	0.28	0.34	0.03	0.03
@ 3% discount	0.44	0.68	0.95	1.29	1.05	1.05
Emission reductions:						
CO_2 (Mt)	5.6	8.9	12.8	19.5	31.2	31.2
NO_X (kt)	2.3	3.7	5.3	8.1	12.9	12.9
Life-Cycle Cost:						
Net Savings (%)	20.2–55.1	25.6–61.5	36.7–71.5	52.0–75.7	24.3–66.8	24.3–66.8
Net Increase (%)	0.6–4.4	1.1–5.1	4.4–9.8	18.2–42.6	34.2–75.7	33.2–75.7
No Change (%)	42.5–76.0	34.6–72.9	18.7–58.9	0.5–28.2	0.0	0.0
Payback (years)	1.5–9.7	2.4–8.3	5.4–10.0	11.8–19.5	15.1–32.5	14.8–32.4
Increase in consumer equipment cost before installation (%) * †	0.7–4.4	2.2–7.2	5.4–13.6	13.5–30.4	36.4–78.5	36.4–78.4
Manufacturer Impact:						

TABLE V.22.—SUMMARY OF MEDIUM-VOLTAGE, DRY-TYPE DISTRIBUTION TRANSFORMERS ANALYTICAL RESULTS—Continued

Criteria	Trial standard level					
	TSL1	TSL2	TSL3	TSL4	TSL5	TSL6
INPV ($ millions)	(2.5)–(1.8)	(4.3)–(3.3)	(6.9)–(5.1)	(7.8)–(3.8)	(17.0)–(2.0)	(17.0)–(2.0)
INPV change (%)	(7.7)–(5.5)	(13.4)–(10.1)	(21.5)–(15.7)	(24.3)–(11.8)	(52.8)–(6.1)	(52.8)–(6.1)

* Percent increase in consumer equipment cost before installation, five-year average material pricing.
† The Department recognizes that these cost changes are the average changes for the Nation, and that some individual customers will experience larger changes, particularly if these customers are not evaluating losses when purchasing transformers.

1. Results for Liquid-Immersed Distribution Transformers

a. Liquid-Immersed Trial Standard Level 6

First, the Department considered the most efficient level (max tech), which would save an estimated total of 9.4 quads of energy through 2038, a significant amount of energy. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 2.1 quads. For the Nation as a whole, TSL6 would have a net cost of $14 billion at a seven-percent discount rate. At this level, the majority of customers would experience an increase in life-cycle costs. As shown in Table V.21, only about 1 to 43 percent of customers would experience lower life-cycle costs, depending on the design line. The payback periods at this standard level are between 26 and 67 years, some of which exceed the anticipated operating life of the transformer. The impacts on manufacturers would be very significant because TSL6 would require a complete conversion to amorphous core technology. These costs would reduce the INPV by as much as 95 percent under the preservation-of-operating-profit scenario. The Department estimates that $59 million of existing assets would be stranded (i.e., rendered useless) and $327 million of conversion capital expenditures would be required to enable the industry to manufacture compliant distribution transformers. The energy savings at TSL6 would reduce the installed generating capacity by 17.3 gigawatts (GW), or roughly 40 large, 400 MW powerplants.[5] The estimated emissions reductions through this same time period are 647.6 Mt of CO_2 and 174.8 kt of NO_X. The Department concludes that at this TSL, the benefits of energy savings, generating capacity reductions, and emission reductions would be outweighed by the potential multi-billion dollar negative net economic cost to the Nation, the economic burden on customers as indicated by large payback periods, and the stranded asset and conversion capital costs that could result in the large reduction in INPV for manufacturers. Consequently, the Department concludes that TSL6, the max tech level, is not economically justified.

b. Liquid-Immersed Trial Standard Level 5

Next, the Department considered TSL5, which would save an estimated total of 6.5 quads of energy through 2038, a significant amount of energy. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 1.45 quads. For the Nation as a whole, TSL5 would have a net cost of $1.1 billion at a seven-percent discount rate. At this level, about 31 to 43 percent of customers would experience lower life-cycle costs, depending on the design line. At this level, 44 to 66 percent of customers would have increased life-cycle costs. The payback periods at this standard level are between 26 and 36 years, some of which exceed the anticipated operating life of the transformer. The impacts on manufacturers would be very significant because TSL5 would require partial conversion to amorphous core technology. The resulting costs would contribute to as much as a 39 percent reduction in the INPV under the preservation-of-operating-profit scenario. The Department estimates that $16 million of existing assets would be stranded and approximately $94 million in conversion capital expenditures would be required to enable the industry to manufacture compliant transformers. The energy savings at TSL5 would reduce the installed generating capacity by 12.1 GW, or roughly 30 large, 400 MW powerplants. The estimated emissions reductions through this same time period are 451.2 Mt of CO_2 and 121.7 kt of NO_X. The Department concludes that at this TSL, the benefits of energy savings, generating capacity reductions, and emission reductions would be outweighed by the potential negative net economic cost to the Nation, the economic burden on customers as indicated by large payback periods, and the stranded asset and conversion capital costs that could result in the large reduction in INPV for manufacturers. Consequently, the Department concludes that TSL5 is not economically justified.

c. Liquid-Immersed Trial Standard Level 4

Next, the Department considered TSL4, which would save an estimated total of 3.4 quads of energy through 2038, a significant amount of energy. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 0.76 quads. For the Nation as a whole, TSL4 would result in a net savings of $1.9 billion at a seven-percent discount rate. For customers, lower life-cycle costs would be experienced by between 35 and 68 percent, depending on the design line, meaning that for some design lines, more than half of the customers would be better off, while for others less than half would benefit. The payback periods for three of the five liquid-immersed design line representative units would be more than half the anticipated operating life of the transformer. For one design line, the payback period is as long as 22 years. The consumer equipment cost before installation would increase by 41 percent for one design line, a significant increase for transformer customers. The energy savings at TSL4 would reduce the installed generating capacity by 6.2 GW, or roughly 16 large, 400 MW powerplants. The estimated emissions reductions through this same time period are 232.8 Mt of CO_2 and 62.8 kt of NO_X. The Department concludes that at this TSL, the benefits of energy savings, generating capacity reductions, emission reductions and national NPV would be outweighed by the economic burden on some customers as indicated by long payback periods and significantly greater first costs. Consequently, the Department

[5] DOE estimates 18 coal-fired power plants and 22 gas-fired power plants can be avoided. See TSD Chapter 13.

concludes that TSL4 is not economically justified.

d. Liquid-Immersed Trial Standard Level 3

Next, the Department considered TSL3, which would save an estimated total of 3 quads of energy through 2038, a significant amount of energy. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 0.67 quads. For the Nation as a whole, TSL3 would have a net savings of $2 billion at a seven-percent discount rate. At this level, lower life-cycle costs would be experienced by between 32 and 50 percent of customers, depending on the design line, meaning that for all the design lines, one-half or less of customers are better off. One of the payback periods is 22 years, exceeding half the anticipated operating life of a transformer. Additionally, the consumer equipment cost before installation increases by 38 percent for one design line, a significant increase for customers. The energy savings at TSL3 would reduce the installed generating capacity by 5.5 GW, or roughly 14 large, 400 MW powerplants. The estimated emission reductions through this same time period are 205.4 Mt of CO_2 and 55.5 kt of NO_X. The Department concludes that at this TSL, the benefits of energy savings, generating capacity reductions, emission reductions and national NPV would be outweighed by the economic burden on some customers as indicated by long payback periods and significantly greater first costs. Consequently, the Department concludes that TSL3 is not economically justified.

e. Liquid-Immersed Trial Standard Level 2

Next, the Department considered TSL2, which would save an estimated total of 2.3 quads of energy through 2038, a significant amount of energy. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 0.51 quads. For the Nation as a whole, TSL2 would have the highest NPV of all the TSLs for liquid-immersed distribution transformers, an estimated $2.3 billion at the seven-percent discount rate. At this level, as shown in Table V.21, between 32 and 42 percent of customers would experience lower life-cycle costs, depending on the design line. The payback periods under TSL2 are between 4 and 18 years, which at most is approximately half the anticipated operating life of the transformer. The energy savings at TSL2 would reduce the installed generating capacity by 4.3 GW, or roughly 11 large, 400 MW powerplants. The estimated emissions reductions through this same time period are 158.2 Mt of CO_2 and 42.7 kt of NO_X. At TSL2, the relatively low costs are outweighed by the benefits, including significant energy savings, generating capacity reductions, emission reductions, maximum national NPV, and benefits to a majority of those customers affected by the standard. After considering the costs and benefits of TSL2, the Department finds that this trial standard level will offer the maximum improvement in efficiency that is technologically feasible and economically justified, and will result in significant conservation of energy. Therefore, the Department today proposes to adopt the energy conservation standards for liquid-immersed distribution transformers at TSL2.

2. Results for Medium-Voltage, Dry-Type Distribution Transformers

a. Medium-Voltage, Dry-Type Trial Standard Level 6

First, the Department considered the most efficient level (max tech), which would save an estimated total of 0.4 quads of energy through 2038. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 0.09 quads. For the Nation as a whole, TSL6 would result in a $30 million benefit at a seven-percent discount rate. However, at this level, the percentage of customers experiencing lower life-cycle costs would be less than 35 percent for the majority of the units analyzed, with one representative unit as low as 24 percent. This means that more than three-quarters of transformer customers making purchases in that design line would experience increases in life-cycle cost. Customer payback periods at this standard level for the majority of units analyzed are 28 years or greater, with one representative unit as high as 32 years, which is approximately the operating life of a transformer. The impacts on manufacturers would be significant, with TSL 6 contributing to a 53-percent reduction in the INPV under the preservation-of-operating-profit scenario. The Department projects that manufacturers will experience negative net annual cash flows during the compliance period, irrespective of the markup scenario. The magnitude of the peak, negative, net annual cash flow would be more than twice that of the positive-base-case cash flow. The energy savings at TSL6 would reduce installed generating capacity by 0.6 GW, or roughly 1.5 large, 400 MW powerplants. The Department estimates the associated emissions reductions through 2038 of 31.2 Mt of CO_2 and 12.9 kt of NO_X. The Department concludes that at this TSL, the benefits of energy savings, generating capacity reductions, emission reductions and national NPV would be outweighed by the economic burdens on customers as indicated by long payback periods and significantly greater first costs, and manufacturers who may experience a drop in INPV of up to 53 percent. Consequently, the Department concludes that TSL6, the max tech level, is not economically justified.

b. Medium-Voltage, Dry-Type Trial Standard Level 5

Next, the Department considered TSL5, which is identical to TSL6 (i.e., for all the representative units, TSL5 and TSL6 have all the same percentage efficiency values). Thus, for the same reasons described above in section V.C.2.a, the Department concludes that TSL5 is not economically justified.

c. Medium-Voltage, Dry-Type Trial Standard Level 4

Next, the Department considered TSL4, which would save a total of 0.3 quads of energy through 2038. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 0.06 quads. For the Nation as a whole, TSL4 would have a net savings of $0.34 billion at a seven-percent discount rate, the maximum NPV for medium-voltage, dry-type distribution transformers. Because for TSL5 and TSL6 the energy savings comes at a high incremental equipment cost, the national net savings for TSL4 is substantially higher than TSL5/6. The percentage of customers experiencing lower life-cycle costs would range between 52 and 76 percent, depending on the design line. However, payback periods at this standard level are as high as 20 years for one design line, which is more than half the operating life of a transformer. In addition, the consumer equipment cost before installation would increase by as much as 30 percent for one design line, a significant increase for customers. Furthermore, the impacts of TSL4 on manufacturers would be significant, contributing to as much as a 24-percent reduction in the INPV under the preservation-of-operating-profit scenario. Additionally, DOE projects that manufacturers will experience negative net annual cash flows during the compliance period, irrespective of the markup scenario. The magnitude of the peak, negative, net annual cash flow is approximately half of that of the positive-base-case cash flow. The energy savings at TSL4 would reduce the installed generating capacity by 0.4 GW, or roughly one large, 400 MW powerplant. The Department estimates associated emissions reductions through 2038 of 19.5 Mt of CO_2 and 8.1 kt of NO_X. Thus, the Department concludes that at this TSL, the benefits of energy savings, generating capacity reductions, positive national NPV, and emission reductions would be outweighed by the long payback periods and significantly greater first costs for some transformer customers and the economic impacts on manufacturers. Consequently, the Department concludes that TSL4 is not economically justified.

d. Medium-Voltage, Dry-Type Trial Standard Level 3

Next, the Department considered TSL3, which would save an estimated 0.2 quads of energy through 2038. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 0.04 quads. For the Nation as a whole, TSL3 would have a net savings of $0.3 billion at a seven-percent discount rate. The percentage of transformer customers who would experience lower life-cycle costs ranges between 37 and 71 percent, depending on the design line, with payback periods of 10 years or less. The impacts on manufacturers at TSL3 would be significant, however, contributing to as much as a 22-percent reduction in the INPV under the preservation-of-operating-profit scenario. In addition, DOE projects the net annual cash flows to be negative during the compliance period, irrespective of the markup scenario. The magnitude of the peak negative net annual cash flow would be approximately half of the positive-base-case cash flow. The energy savings at TSL3 would reduce the installed generating capacity by 0.3 GW, or roughly 0.8 of a large, 400 MW powerplant. The Department estimates the associated emissions reductions through 2038 of 12.8 Mt of CO_2 and 5.3 kt of NO_X. Thus, the Department concludes that at this TSL, the benefits of energy savings, generating capacity reductions, positive national NPV, LCC savings, and emission reductions would be outweighed by the economic impacts on manufacturers. Consequently, the Department concludes that TSL3 is not economically justified.

e. Medium-Voltage, Dry-Type Trial Standard Level 2

Next, the Department considered TSL2, which would save an estimated total of 0.1 quad of energy through 2038. Discounted at 7 percent, the energy savings through 2038 would reduce to approximately 0.03 quads. For the Nation as a whole, TSL2 would have a net savings of $0.2 billion at a seven-percent discount rate. The percentage of transformer customers experiencing lower life-cycle costs ranges between 26 and 61 percent, depending on the design line, with payback periods of eight years or less. The Department considers impacts on manufacturers at this standard level (at most a 13-percent reduction in the INPV under the preservation-of-operating-profit scenario) to be reasonable. The energy savings at TSL2 would reduce the installed generating capacity by 0.2 GW, or roughly half of a large, 400 MW powerplant. The Department estimates associated emissions reductions through 2037 of 8.9 Mt of CO_2 and 3.7 kt of NO_X. Thus, the Department concludes that this TSL has positive energy savings, generating capacity reductions, emission reductions, national NPV, benefits to transformer customers, and reasonable impacts on transformer manufacturers. After considering the costs and benefits of TSL2, the Department finds that this trial standard level will offer the maximum improvement in efficiency that is technologically feasible and economically justified, and will result in significant conservation of energy. Therefore, the Department today proposes to adopt the energy conservation standards for medium-voltage, dry-type distribution transformers at TSL2.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Order 12866

The Department has determined today's regulatory action is a ''significant regulatory action'' under section 3(f)(1) of Executive Order 12866, ''Regulatory Planning and Review.'' 58 FR 51735 (October 4, 1993). Accordingly, today's action required a regulatory impact analysis (RIA) and, under the Executive Order, was subject to review by the Office of Information and Regulatory Affairs (OIRA) in the Office of Management and Budget (OMB). The Department presented to OIRA for review the draft proposed rule and other documents prepared for this rulemaking, including the RIA, and has included these documents in the rulemaking record. They are available for public review in the Resource Room of DOE's Building Technologies Program, 1000 Independence Avenue, SW., Washington, DC, (202) 586–9127, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays.

Regarding the Department's preparation of a regulatory alternatives analysis, ASE said the Department should fully describe non-regulatory alternatives, including penetration rates, in the NOPR analysis. (Public Meeting Transcript, No. 56.12 at pp. 252–253) The Department followed the examples established by prior rulemakings in regulatory impact reporting. The RIA, formally entitled, ''Regulatory Impact Analysis for Proposed Energy Conservation Standards for Electrical Distribution Transformers,'' is contained in the TSD prepared for the rulemaking. The RIA consists of: (1) A statement of the problem addressed by this regulation, and the mandate for government action; (2) a description and analysis of the feasible policy alternatives to this regulation; (3) a quantitative comparison of the impacts of the alternatives; and (4) the national economic impacts of the proposed standard.

The RIA calculates the effects of feasible policy alternatives to distribution transformer standards, and provides a quantitative comparison of the impacts of the alternatives. The Department evaluated each alternative in terms of its ability to achieve significant energy savings at reasonable costs, and compared it to the effectiveness of the proposed rule. The Department analyzed these alternatives using a series of regulatory scenarios as input to the NES/shipments model for distribution transformers, which it modified to allow inputs for voluntary measures.

The Department identified the following major policy alternatives for achieving increased distribution transformer energy efficiency:

- No new regulatory action
- Consumer rebates
- Consumer tax credits
- Manufacturer tax credits
- Voluntary energy-efficiency targets
- Early replacement
- Bulk government purchases

The Department evaluated each alternative in terms of its ability to achieve significant energy savings at reasonable costs (see Table VI.1), and compared it to the effectiveness of the proposed rule.

TABLE VI.1.—NON-REGULATORY ALTERNATIVES AND THE PROPOSED STANDARD

Policy alternatives	Type	Primary energy savings (quads)	Net present value (billion $2004)	
			7% discount rate	3% discount rate
No New Regulatory Action		0.0	0.0	0.0
Consumer Rebates	Liquid	0.0	0.0	0.0
	MV* Dry	0.007	0.013	0.042
	Total	0.007	0.013	0.042
Consumer Tax Credits	Liquid	0.058	0.058	0.218
	MV Dry	0.004	0.008	0.025
	Total	0.06	0.07	0.24
Manufacturer Tax Credits	Liquid	0.029	0.028	0.108
	MV Dry	0.002	0.004	0.013
	Total	0.03	0.03	0.12
Proposed Standards at TSL2	Liquid	2.28	2.31	8.78
	MV Dry	0.113	0.207	0.683
	Total	2.40	2.52	9.47

* MV = medium-voltage.

Table VI.1 shows the NES and NPV of each of the applicable non-regulatory alternatives. The results are reported for liquid-immersed and medium-voltage, dry-type transformers as well as in total. The case in which no regulatory action is taken with regard to distribution transformers constitutes the base case (or ''No Action'') scenario. Since this is the base case, energy savings and NPV are zero by definition. For comparison, the table includes the impacts of the proposed energy conservation standards. The NPV amounts shown in Table VI.1 refer to the NPV based on two discount rates (seven percent and three percent real). DOE did not consider three of the policy alternatives, voluntary energy-efficiency targets, early replacement, and bulk government purchases, because, as discussed in the RIA, DOE believes they would not significantly impact the distribution transformers covered by this NOPR.

None of the alternatives DOE examined would save as much energy or have an NPV as high as the proposed standards. Also, several of the alternatives would require new enabling legislation, such as consumer or manufacturer tax credits, since authority to carry out those alternatives does not presently exist. Additional detail on the regulatory alternatives is found in the RIA report of the TSD.

B. Review Under the Regulatory Flexibility Act/Initial Regulatory Flexibility Analysis

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis 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 (August 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. The Department has made its procedures and policies available on the Office of General Counsel's Web site: *http://www.gc.doe.gov.*

Small businesses, as defined by the Small Business Administration (SBA) for the distribution transformer manufacturing industry, are manufacturing enterprises with 750 employees or fewer. The Department reviewed today's proposed rule under the provisions of the Regulatory Flexibility Act and the procedures and policies published on February 19, 2003. On the basis of the foregoing, DOE determined that it cannot certify that the proposed rule (trial standard level 2, or TSL2), if promulgated, would have no significant economic impact on a substantialnumber of small entities. The Department made this determination because of the potential impacts that the proposed standard levels for medium-voltage, dry-type distribution transformers would have on the small businesses that manufacture them. However, the Department notes that it explicitly considered the impacts on small medium-voltage, dry-type businesses in selecting TSL2, rather than selecting a higher trial standard level.

The revenue attributable to the medium-voltage, dry-type superclass represents only about six percent of the total revenues of the industry affected by this rulemaking (i.e., the sum of revenues from the liquid-immersed superclass and the medium-voltage, dry-type superclass). Because of the potential impacts of today's proposed rule on small, medium-voltage, dry-type manufacturers, DOE has prepared an initial regulatory flexibility analysis (IRFA) for this rulemaking. The IRFA divides potential impacts on small businesses into two broad categories: (1) Impacts associated with transformer design and manufacturing, and (2) impacts associated with demonstrating compliance with the standard using DOE's test procedure. The Department's test procedure rule does not require manufacturers to take any action in the absence of final energy conservation standards for distribution transformers, and thus any impact of that rule on small businesses would be triggered by the promulgation of the standard proposed today.

The Department believes that there will be no significant economic impact on a substantial number of small liquid-immersed manufacturers because the transformers in the liquid-immersed superclass are largely customized, and small businesses can compete because many of these transformers are unique designs produced in relatively small quantities for a given order. Small manufacturers of liquid-immersed transformers tend not to compete on the higher-volume products and often produce transformers for highly specific applications. This strategy allows small manufacturers of liquid-immersed units to be competitive in certain liquid-immersed product markets. Implementation of an energy conservation standard would have a relatively minor differential impact on small manufacturers of liquid-immersed distribution transformers. Disadvantages to small businesses, such as having little leverage over suppliers (e.g., core steel suppliers), are present with or without an energy conservation standard. Due to the purchasing characteristics of their customers, small manufacturers of liquid-immersed transformers currently produce transformers at TSL2, the proposed level. Thus, conversion costs (e.g., research and development costs, capital investments) and the associated manufacturer impacts on small businesses are expected to be insignificant at the proposed level, TSL2.

The potential impacts on medium-voltage, dry-type manufacturers (and also the compliance demonstration cost for liquid-immersed manufacturers) are discussed in the following sections. The Department has transmitted a copy of this IRFA to the Chief Counsel for Advocacy of the Small Business Administration for review.

1. Reasons for the Proposed Rule

Part C of Title III of the Energy Policy and Conservation Act (EPCA) provides for an energy conservation program for certain commercial and industrial equipment. (42 U.S.C. 6311–6317) In particular, section 346 of EPCA states that the Secretary of Energy must prescribe testing requirements and energy conservation standards for those distribution transformers for which the Secretary determines that standards would be technologically feasible and economically justified, and would result in significant energy savings, although section 325(v) of EPCA in effect modifies this provision by specifying standards for low voltage, dry-type distribution transformers. (42 U.S.C. 6295(v) and 6317(a))

On October 22, 1997, the Secretary of Energy issued a determination that ''based on its analysis of the information now available, the Department has determined that energy conservation standards for transformers appear to be technologically feasible and economically justified, and are likely to result in significant savings.'' 62 FR 54809. Recognizing that fact, EPACT 2005 set minimum efficiency levels for low-voltage dry-type distribution transformers and allowed the Department to continue its analysis and rulemaking for liquid-immersed and medium-voltage dry-type distribution transformers.

2. Objectives of, and Legal Basis for, the Proposed Rule

The Department selects any new or amended standard to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. (See 42 U.S.C. 6295(o)(2)(A), 6313(a), and 42 U.S.C. 6317(a) and (c)) If a proposed standard is not designed to achieve the maximum improvement in energy efficiency or the maximum reduction in energy use that is technologically feasible, the Secretary states the reasons for this in the proposed rule. To determine whether economic justification exists, the Department reviews comments received and conducts analysis to determine whether the economic benefits of the proposed standard exceed the costs to the greatest extent practicable, taking into consideration the seven factors set forth in 42 U.S.C. 6295(o)(2)(B)(i) (see Section II.B of this Notice). Further information concerning the background of this rulemaking is provided in Chapter 1 of the TSD.

3. Description and Estimated Number of Small Entities Regulated

By researching the distribution transformer market, developing a database of manufacturers, and conducting interviews with manufacturers (both large and small), the Department was able to estimate the number of small entities that would be regulated under an energy conservation standard. See chapter 12 of the TSD for further discussion about the methodology used in the Department's manufacturer impact analysis and its analysis of small-business impacts.

The liquid-immersed superclass accounts for about $1.3 billion in annual sales and employment of about 4,250 production employees in the United States. The Department estimates that, of the approximately 25 U.S. manufacturers that make liquid-immersed distribution transformers, about 15 of them are small businesses. About five of the small businesses have fewer than 100 employees.

The medium-voltage, dry-type superclass accounts for about $84 million in annual sales and employment of about 250–330 production employees in the United States. The medium-voltage, dry-type market is relatively small compared to that of the liquid-immersed superclass. The Department estimates that, of the 25 U.S. manufacturers that make medium-voltage, dry-type distribution transformers, about 20 of them are small businesses. About ten of these small businesses have fewer than 100 employees.

4. Description and Estimate of Compliance Requirements

Potential impacts on small businesses come from two broad categories of compliance requirements: (1) Impacts associated with transformer design and manufacturing, and (2) impacts associated with demonstrating compliance with the standard using the Department's test procedure.

In regard to impacts associated with transformer design and manufacturing, the margins and/or market share of small businesses in the medium-voltage, dry-type superclass could be hurt in the long term by today's proposed level, TSL2. At TSL2, as opposed to TSL1, small manufacturers would have less flexibility in choosing a design path. However, as discussed under subsection 6 (Significant alternatives to the rule) below, the Department expects that the differential impact on small, medium-voltage, dry-type businesses (versus large businesses) would be smaller in moving from TSL1 to TSL2 than it would be in moving from TSL2 to TSL3. The rationale for the Department's expectation is best discussed in a comparative context and is therefore elaborated upon in subsection 6 (Significant alternatives to the rule). As discussed in the introduction to this IRFA, DOE expects that the differential impact associated with transformer design and manufacturing on small, liquid-immersed businesses would be negligible.

In regard to compliance demonstration, the Department's test procedure for distribution transformers employs an Alternative Efficiency Determination Method (AEDM) which would ease the burden on manufacturers. 10 CFR Part 431, Subpart K, Appendix A; 71 FR 24972. The AEDM involves a sampling procedure to compare manufactured products' efficiencies with those predicted by computer design software. Where the manufacturer uses an AEDM for a basic model, it would not be required to test units of the basic model to determine its efficiency for purposes of establishing compliance with DOE requirements. The professional skills necessary to execute the AEDM include the following: (1) Transformer design software expertise (or access to such expertise possessed by a third party), and (2) electrical testing expertise and moderate expertise with experimental statistics (or access to such expertise possessed by a third party). The Department's test procedure would require periodic verification of the AEDM.

The Department's test procedure also requires manufacturers to calibrate equipment used for testing the efficiency of transformers. Calibration records would need to be maintained, if the proposed energy conservation standard is promulgated.

The testing, reporting, and recordkeeping requirements associated with an energy conservation standard and its related test procedure would be identical, irrespective of the trial standard level chosen. Therefore, for both the liquid-immersed and medium-voltage, dry-type superclasses, testing, reporting, and recordkeeping requirements have not entered into the Department's choice of trial standard level for today's proposed rule.

5. Duplication, Overlap, and Conflict With Other Rules and Regulations

The Department is not aware of any rules or regulations that duplicate, overlap, or conflict with the rule being proposed today.

6. Significant Alternatives to the Rule

The primary alternatives to the proposed rule considered by the Department are the other trial standard levels besides the one being proposed today, TSL2. These alternative trial standard levels and their associated impacts on small business are discussed in the subsequent paragraphs. In addition to the other trial standard levels considered, the TSD associated with this proposed rule includes a report referred to in section VI.A above as the RIA. This report discusses the following policy alternatives: (1) No new regulatory action, (2) consumer rebates, (3) consumer tax credits, and (4) manufacturer tax credits. The energy savings and beneficial economic impacts of these regulatory alternatives are one to two orders of magnitude smaller than those expected from today's proposed rule. Finally, the Department has not considered abbreviated testing requirements for small businesses, but invites stakeholder comment on abbreviating such requirements for small businesses.

The entire medium-voltage, dry-type industry has such low shipments that no designs are produced at high volume. There is little repeatability of designs, so small businesses can competitively produce many medium-voltage, dry-type, open-wound designs. The medium-voltage, dry-type industry as a whole primarily has experience producing baseline transformers and transformers that would comply with TSL1. In addition, the industry produces a significant number of units that would comply with TSL2, but approximately one percent or less of the market would comply with TSL3 or higher. Therefore, all manufacturers, including small businesses, would have to develop designs to enable compliance with TSL3 or higher—such research and development costs would be more burdensome to small businesses. Product redesign costs tend to be fixed and do not scale with sales volume. Thus, small businesses would be at a relative disadvantage at TSL3 and higher because research and development efforts would be on the same scale as those for larger companies, but these expenses would be recouped over smaller sales volumes.

At TSL3 and above, DOE estimates that net cash flows for the medium-voltage, dry-type industry would go negative during the compliance period. At TSL3 and above, the impacts on the industry as a whole are large and affect businesses of all sizes, but there would be some differential, increased impacts on small businesses. For example, at TSL3 and above, the use of grain-oriented silicon core steel of M3 or better will be needed. Cutting M3 core steel on the core-mitering equipment typically purchased by smaller businesses can be problematic because of the extremely thin laminations.

At TSL2, the level proposed today, all medium-voltage, dry-type transformer designs would have to have mitered cores. (Mitering means the transformer core's joints intersect at 45 degree angles, rather than at 90 degree angles as is true for ''butt-lap'' designs; buttlap designs are less energy efficient.) The mitered core construction technique could constrain the core-mitering resources of small businesses that share core-cutting capacity with production lines for other transformers that are not covered by this rulemaking (e.g., low-voltage, dry-type distribution transformers). At TSL1, many kVA ratings could still be constructed using butt-lap joints, alleviating this constraint on core-mitering resources. Thus, TSL1 is less capital-intensive for small businesses than TSL2 (large businesses would likely miter nearly all medium-voltage cores, even at TSL1). In an industry such as the medium-voltage, dry-type transformer industry, which is heavily consolidated already, there is the risk that TSL2 could lead to further advantage for the largest manufacturers and thus further concentrate the industry's production. The top three manufacturers produce over 75 percent of all the transformers in the medium-voltage, dry-type superclass. Of these three, two of them are small businesses.

The primary difference between TSL1 and TSL2 from the manufacturers' viewpoint is that TSL1 preserves more design pathways, each trading off material for capital. Butt-lap designs would be cost-effective at TSL1 for some kVA ratings, which would allow small businesses to remain more competitive because they would not necessarily have to make large capital outlays. TSL2 cannot be met cost-effectively with butt-lap designs; thus TSL2 could hurt the margins or decrease the market share of small businesses in the long run. Some small businesses might opt to purchase pre-mitered cores at TSL2 rather than investing in core-mitering equipment, which would likely hurt their margins. However, the differential impact on small businesses (versus large businesses) is expected to be lower in moving from TSL1 to TSL2 than in moving from TSL2 to TSL3. Today, the market already demands significant quantities of medium-voltage, dry-type transformers that meet TSL2.

Chapter 12 of the TSD contains more information about the impact of this rulemaking on manufacturers. The Department interviewed six small businesses affected by this rulemaking (see also section IV.F.1 above). The Department also obtained information about small business impacts while interviewing manufacturers that exceed the small business size threshold of 750 employees.

C. Review Under the Paperwork Reduction Act

Adoption of today's proposed rule would have the effect of requiring that manufacturers follow certain record-keeping requirements in the test procedure for distribution transformers, not just for purposes of making representations, but also to determine compliance even in the absence of any representation. As set forth in the test procedure, manufacturers will become subject to the record-keeping requirements when today's proposed energy conservation standard for distribution transformers takes effect. 10 CFR Part 431, Subpart K, Appendix A; 71 FR 24972. Thus, the standard will impose new information or record keeping requirements, and Office of Management and Budget clearance is required under the Paperwork Reduction Act. (44 U.S.C. 3501 *et seq.*)

The test procedure for distribution transformers requires manufacturers to calibrate equipment used for testing the efficiency of transformers. 10 CFR Part 431, Subpart K, Appendix A; 71 FR 24972. Manufacturers must also document (1) the basis for their calibration of any equipment for which no national calibration standard exists, (2) their calibration procedures, and (3) the date when they calibrated their equipment. The Department drew these provisions from, and in some cases they are identical to, provisions in NEMA TP 2–1998. The Department understands that NEMA, in turn, based them on provisions of the International Standards Organization (ISO) 9000 series documents. These documents are voluntary standards widely recognized throughout industry and internationally as setting forth sound quality assurance methods. The Department incorporated such provisions in its test procedure because it believes that any manufacturer doing testing should employ them to assure sound and accurate results. The Department understands that they are already widely followed by manufacturers, in the interest of assuring they provide to their customers equipment that meets customer specifications. Thus, DOE believes that little or no additional record-keeping burden would be imposed by today's proposed rule.

The test procedure also allows manufacturers, under certain circumstances, to determine the efficiencies of their distribution transformers through use of methods other than testing. The test procedure includes Alternative Efficiency Determination Methods (AEDM) to reduce testing burden. 10 CFR Part 431, Subpart K, Appendix A; 71 FR 24972. Each manufacturer that has used an AEDM must have available for inspection by the Department records showing: The method or methods used; the mathematical model, the engineering or statistical analysis, computer simulation or modeling, and other analytic evaluation of performance data on which the AEDM is based; complete test data, product information, and related information that the manufacturer has used to substantiate the AEDM; and the calculations used to determine the efficiency and total power losses of each basic model to which the AEDM was applied. 10 CFR Part 431, Subpart K, Appendix A; 71 FR 24972. This information must be recorded and maintained for each AEDM the manufacturer uses. This requirement is designed to enable the Department to determine, if necessary, that these mathematical models have been properly used to rate transformer efficiencies.

The Department is submitting to the OMB, simultaneously with the publication of this proposed rule, these record-keeping requirements for review and approval under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* An agency may not impose, and a person is not required to respond to, such a requirement unless it has been reviewed and assigned a control number by OMB. Interested persons may obtain a copy of the Paperwork Reduction Act submission from the contact person named in this notice.

Interested persons are invited to submit comments to OMB addressed to: Department of Energy Desk Officer, Office of Information and Regulatory Affairs, OMB, 725 17th Street, NW., Washington DC, 20503. Persons submitting comments to OMB also are requested to send a copy to the DOE contact person at the address given in the addresses section of this notice. OMB is particularly interested in comments on: (1) The necessity of the proposed record-keeping provisions, including whether the information will have practical utility; (2) the accuracy of the Department's estimates of the burden; (3) ways to enhance the quality, utility, and clarity of the information to be maintained; and (4) ways to minimize the burden of the requirements on respondents.

D. Review Under the National Environmental Policy Act

The Department is preparing an environmental assessment of the impacts of the proposed rule and DOE anticipates completing a Finding of No Significant Impact (FONSI) before publishing the final rule on distribution transformers, pursuant to the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), the regulations of the Council on Environmental Quality (40 CFR parts 1500–1508), and the Department's regulations for compliance with the National Environmental Policy Act (10 CFR part 1021).

E. Review Under Executive Order 13132

Executive Order 13132, ''Federalism,'' 64 FR 43255 (August 4, 1999) imposes certain requirements on 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. The Department has examined today's proposed rule and has determined that it does not preempt State law and does not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. 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 the Department 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'' 61 FR 4729 (February 7, 1996) 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. 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. The Department 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 (Pub. L. 104–4) (UMRA) requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and Tribal governments and the private sector. 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) (also available at *http://www.gc.doe.gov*). The proposed rule published today contains neither an intergovernmental mandate nor a mandate that may result in expenditure of $100 million or more in any year, so these requirements do not apply.

H. Review Under the Treasury and General Government Appropriations Act of 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

The Department has determined, under Executive Order 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights,'' 53 FR 8859 (March 18, 1988), that this regulation would not result in any takings which might require compensation under the Fifth Amendment to the United States Constitution.

J. Review Under the Treasury and General Government Appropriations Act of 2001

Section 515 of the Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516, note) provides for agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by OMB. The 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). The Department has reviewed today's notice 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 the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget, a Statement of Energy Effects for any proposed significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgated 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.

While this proposed rule is a significant regulatory action under Executive Order 12866, it is not likely to have a significant adverse effect on the supply, distribution, or use of energy, nor has it been designated by the Administrator of OIRA as a significant energy action. Thus, DOE has not prepared a Statement of Energy Effects.

L. Review Under Section 32 of the Federal Energy Administration Act of 1974

The Department is required by section 32 of the Federal Energy Administration Act (FEAA) of 1974 to inform the public of the use and background of any commercial standard in a proposed rule. (15 U.S.C. 788) While the Department had considered a commercial voluntary standard (NEMA TP 1–2002) as one of the trial standard levels, it did not choose to regulate either liquid-immersed or medium-voltage dry-type distribution transformers at this efficiency level. Because today's proposed rule adopts more stringent efficiency levels, Section 32 of the FEAA does not apply.

M. Review Under the Information Quality Bulletin for Peer Review

On December 16, 2004, the Office of Management and Budget (OMB), in consultation with the Office of Science and Technology (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.

The Department's Office of Energy Efficiency and Renewable Energy, Building Technologies Program, held formal in-progress peer reviews covering the analyses (e.g., screening/engineering analysis, life-cycle cost analysis, manufacturing impact analysis, and utility impact analysis) used in conducting the energy efficiency standards development process on June 28–29, 2005. The in-progress review is a rigorous, formal and documented evaluation process using objective criteria and qualified and independent reviewers to make a judgment of the technical/scientific/business merit, the actual or anticipated results, and the productivity and management effectiveness of programs and/or projects. The Building Technologies Program staff is preparing a peer review report which, upon completion, will be disseminated on the Office of Energy Efficiency and Renewable Energy's Web site and included in the administrative record for this rulemaking.

VII. Public Participation

A. Attendance at Public Meeting

The time and date of the public meeting are listed in the DATES section at the beginning of this notice of proposed rulemaking. The public meeting will be held at the U.S. Department of Energy, Forrestal Building, Room 1E245, 1000 Independence Avenue, SW., Washington, DC 20585–0121. To attend the public meeting, please notify Ms. Brenda Edwards-Jones at (202) 586–2945. Foreign nationals visiting DOE Headquarters are subject to advance security screening procedures, requiring a 30-day advance notice. Any foreign national wishing to participate in the meeting should advise DOE of this fact as soon as possible by contacting Ms. Brenda Edwards-Jones to initiate the necessary procedures.

B. Procedure for Submitting Requests To Speak

Any person who has an interest in today's notice, or who is a representative of a group or class of persons that has an interest in these issues, may request an opportunity to make an oral presentation. Such persons may hand-deliver requests to speak, along with a computer diskette or CD in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format to the address shown in the **ADDRESSES** section at the beginning of this notice of proposed rulemaking between the hours of 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Requests may also be sent by mail or e-mail to: *Brenda.Edwards-Jones@ee.doe.gov*.

Persons requesting to speak should briefly describe the nature of their interest in this rulemaking and provide a telephone number for contact. The Department requests persons selected to be heard to submit an advance copy of their statements at least two weeks before the public meeting. At its discretion, DOE may permit any person who cannot supply an advance copy of their statement to participate, if that person has made advance alternative arrangements with the Building Technologies Program. The request to give an oral presentation should ask for such alternative arrangements.

C. Conduct of Public Meeting

The Department 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 5 U.S.C. 553 and section 336 of EPCA, 42 U.S.C. 6306. A court reporter will be present to record the proceedings and prepare a transcript. The Department 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. The Department will present summaries of comments received before the public meeting, allow time for presentations by participants, and encourage all interested parties to share their views on issues affecting this rulemaking. Each participant will be allowed to make a prepared general statement (within time limits determined by DOE), before the discussion of specific topics. The Department will permit 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. Department 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.

The Department will make the entire record of this proposed rulemaking, including the transcript from the public meeting, available for inspection at the U.S. Department of Energy, Forrestal Building, Room 1J–018 (Resource Room of the Building Technologies Program), 1000 Independence Avenue, SW., Washington, DC, (202) 586–9127, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Any person may buy a copy of the transcript from the transcribing reporter.

D. Submission of Comments

The Department will accept comments, data, and information regarding the proposed rule before or after the public meeting, but no later than the date provided at the beginning of this notice of proposed rulemaking. Please submit comments, data, and information electronically. Send them to the following e-mail address: *TransformerNOPRComment@ee.doe.gov.* Submit electronic comments in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format and avoid the use of special characters or any form of encryption. Comments in electronic format should be identified by the docket number EE–RM/STD–00–550 and/or RIN number 1904–AB08, and wherever possible carry the electronic signature of the author. Absent an electronic signature, comments submitted electronically must be followed and authenticated by submitting the signed original paper document. No telefacsimiles (faxes) will be accepted.

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 two copies: One copy of the document including all the information believed to be confidential, and one copy of the document with the information believed to be confidential deleted. The Department of Energy will make its own determination about the confidential status of the information and treat it according to its determination.

Factors of interest to the Department 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.

E. Issues on Which DOE Seeks Comment

The Department is particularly interested in receiving comments and views of interested parties concerning:

(1) The proposed tables of efficiency ratings, and specifically areas where the underlying analytical methods followed for developing the efficiency values resulted in discontinuities.

(2) The Department's treatment of rebuilt or refurbished transformers in this rulemaking and the potential impact on consumers, manufacturers, and national energy use if they were excluded.

(3) Whether less-flammable, liquid-immersed distribution transformers

should be included in the same product class as medium-voltage, dry-type transformers. Currently the Department considers dry-type transformers and liquid-immersed transformers as members of separate product classes.

(4) Whether stakeholders believe a minimum efficiency standard for liquid-immersed distribution transformers would contribute to design standardization, and encourage manufacturers to move to countries with lower labor costs.

(5) The appropriateness of using discount rates of seven percent and three percent real to discount future energy savings and emissions reductions.

(6) Whether the Department should include space occupancy costs in the cost of transformers as a means of accounting for space constraints.

(7) The IRFA and the potential impacts on small businesses affected by this rulemaking. Although the Department is expressly inviting comments related to the medium-voltage, dry-type superclass, the Department also welcomes comment on its understanding that there would be no significant economic impact on a substantial number of small entities within the liquid-immersed superclass alone.

VIII. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of today's notice of proposed rulemaking.

List of Subjects in 10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation, Reporting and record keeping requirements.

Issued in Washington, DC, on July 20, 2006.

Alexander A. Karsner,

Assistant Secretary, Energy Efficiency and Renewable Energy.

For the reasons set forth in the preamble, Chapter II of Title 10, Code of Federal Regulations, Subpart K of Part 431 is proposed to be amended 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. Section 431.196 is amended by revising paragraphs (b) and (c) to read as follows:

§ 431.196 Energy conservation standards and their effective dates.

* * * * *

(b) *Liquid-Immersed Distribution Transformers.* Liquid-immersed distribution transformers manufactured on or after January 1, 2010, shall have an efficiency no less than:

Single-phase		Three-phase	
kVA	Efficiency (%) *	kVA	Efficiency (%) *
10	98.40	15	98.36
15	98.56	30	98.62
25	98.73	45	98.76
37.5	98.85	75	98.91
50	98.90	112.5	99.01
75	99.04	150	99.08
100	99.10	225	99.17
167	99.21	300	99.23
250	99.26	500	99.32
333	99.31	750	99.24
500	99.38	1000	99.29
667	99.42	1500	99.36
833	99.45	2000	99.40
		2500	99.44

* 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 55°C and 50 percent of nameplate load.

(c) *Medium-Voltage Dry-Type Distribution Transformers.* Medium-voltage dry-type distribution transformers manufactured on or after January 1, 2010, shall have an efficiency no less than:

Single-phase				Three-phase			
BIL kVA	20–45 kV efficiency (%) *	46–95 kV efficiency (%) *	≥96 kV efficiency (%) *	BIL kVA	20–45 kV efficiency (%) *	46–95 kV efficiency (%) *	≥96 kV efficiency (%) *
15	98.10	97.86		15	97.50	97.19	
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

Single-phase				Three-phase			
BIL kVA	20–45 kV efficiency (%) *	46–95 kV efficiency (%) *	≥96 kV efficiency (%) *	BIL kVA	20–45 kV efficiency (%) *	46–95 kV efficiency (%) *	≥96 kV efficiency (%) *
				2500	99.31	99.23	99.20

* 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 50 percent of nameplate load.

[FR Doc. 06–6537 Filed 8–3–06; 8:45 am]

BILLING CODE 6450–01–P