



102ND GENERAL ASSEMBLY

State of Illinois

2021 and 2022

SB0311

Introduced 2/19/2021, by Sen. Christopher Belt

SYNOPSIS AS INTRODUCED:

See Index

Amends the Illinois Power Agency Act. In provisions concerning the renewable portfolio standards, specifies the goals for procurement of renewable energy credits and cost-effective renewable energy resources that shall be included in the long-term renewable resources procurement plan and makes other changes concerning these procurements and provides for the calculation of the cost of equity for the purposes of recovering all reasonable and prudently incurred costs of energy efficiency measures from retail customers. Provides that savings of fuels other than electricity achieved by measures that educate about, incentivize, encourage, or otherwise support the use of electricity to power vehicles shall count towards the applicable annual incremental goal and shall not be included in determining certain limits. Amends the Public Utilities Act. Provides that an electric utility that serves less than 3,000,000 retail customers but more than 500,000 customers in this State may plan for, construct, install, control, own, manage, or operate photovoltaic electricity production facilities and any energy storage facilities that are planned for, constructed, installed, controlled, owned, managed, or operated in connection with photovoltaic electricity production facilities without obtaining a certificate of public convenience and necessity subject to specified terms and conditions. Provides that a public utility that provided electric service to at least 1,000,000 retail customers in Illinois and gas service to at least 500,000 retail customers in Illinois may elect to recover its natural gas delivery services costs through a performance-based rate. Provides that, beginning in 2022, without obtaining any approvals from the Commission or any other agency, regardless of whether any such approval would otherwise be required, a participating utility that is a combination utility shall pay \$1,000,000 per year for 10 years to the energy low-income and support program. Adds provisions authorizing certain utilities to plan for, construct, install, control, own, manage, or operate electric vehicle charging infrastructure. Amends the Prevailing Wage Act to include specified facilities financed in whole or in part with renewable energy resources in the definition of "public works". Makes other changes. Effective immediately.

LRB102 15398 SPS 20761 b

A BILL FOR

1 AN ACT concerning regulation.

2 **Be it enacted by the People of the State of Illinois,**
3 **represented in the General Assembly:**

4 Section 1. Findings.

5 (a) Over the last decade, the General Assembly has
6 empowered the State of Illinois to become a national leader in
7 the implementation of a progressive energy policy. The General
8 Assembly has enacted laws to increase investment in equitable
9 energy efficiency, clean and renewable energy, and continued
10 modernization of the electric grid. The General Assembly has
11 further encouraged and enabled investment in the clean energy
12 economy in Illinois to ensure that the State and its citizens,
13 including low-income individuals, are equipped to enjoy the
14 opportunities and benefits of a smart grid and smart metering
15 infrastructure platform, adopt and deploy cost-effective
16 distributed energy resource technologies and devices, and
17 benefit from investments in job training and job creation. To
18 ensure this progress can be sustained, the General Assembly
19 finds and declares the following:

20 (1) The State of Illinois is a geographically large
21 and diverse State and communities in central and southern
22 Illinois have different strengths and needs than those in
23 the northern region of the State.

24 (2) The changing energy marketplace is having a

1 measurable effect on employment, economic development,
2 business growth, non-profit health, school funding, local
3 government stability, and community development in central
4 and southern Illinois, and updated policies are needed to
5 address those impacts.

6 (3) The State should accelerate the development and
7 adoption of technologies and facilities in central and
8 southern Illinois so that there are greater opportunities
9 for investment in clean energy, electric vehicles, energy
10 storage facilities, management of peak load, and grid
11 stability and reliability.

12 (4) Continuing the transparent, predictable, and
13 accountable policy that allows electric utilities to
14 undertake needed system investments and earn a fair return
15 on their investments in an efficient manner is the best
16 method for building a smart, reliable grid that is
17 equipped for the clean energy future.

18 (b) The General Assembly therefore finds that it is
19 necessary to develop an energy policy for central and southern
20 Illinois that accelerates achievement of the State's renewable
21 portfolio standard by creating new opportunities for
22 investments in solar assets, building an electric vehicle
23 charging infrastructure across hundreds of miles of roads,
24 increasing research and deployment of new clean energy
25 technology, and continuing to utilize transparent annual
26 reviews to recover costs and set reasonable rates.

1 Section 5. The Illinois Power Agency Act is amended by
2 changing Sections 1-10 and 1-75 as follows:

3 (20 ILCS 3855/1-10)

4 Sec. 1-10. Definitions.

5 "Agency" means the Illinois Power Agency.

6 "Agency loan agreement" means any agreement pursuant to
7 which the Illinois Finance Authority agrees to loan the
8 proceeds of revenue bonds issued with respect to a project to
9 the Agency upon terms providing for loan repayment
10 installments at least sufficient to pay when due all principal
11 of, interest and premium, if any, on those revenue bonds, and
12 providing for maintenance, insurance, and other matters in
13 respect of the project.

14 "Authority" means the Illinois Finance Authority.

15 "Brownfield site photovoltaic project" means photovoltaics
16 that are:

17 (1) interconnected to an electric utility as defined
18 in this Section, a municipal utility as defined in this
19 Section, a public utility as defined in Section 3-105 of
20 the Public Utilities Act, or an electric cooperative, as
21 defined in Section 3-119 of the Public Utilities Act; and

22 (2) located at a site that is regulated by any of the
23 following entities under the following programs:

24 (A) the United States Environmental Protection

1 Agency under the federal Comprehensive Environmental
2 Response, Compensation, and Liability Act of 1980, as
3 amended;

4 (B) the United States Environmental Protection
5 Agency under the Corrective Action Program of the
6 federal Resource Conservation and Recovery Act, as
7 amended;

8 (C) the Illinois Environmental Protection Agency
9 under the Illinois Site Remediation Program; or

10 (D) the Illinois Environmental Protection Agency
11 under the Illinois Solid Waste Program.

12 "Clean coal facility" means an electric generating
13 facility that uses primarily coal as a feedstock and that
14 captures and sequesters carbon dioxide emissions at the
15 following levels: at least 50% of the total carbon dioxide
16 emissions that the facility would otherwise emit if, at the
17 time construction commences, the facility is scheduled to
18 commence operation before 2016, at least 70% of the total
19 carbon dioxide emissions that the facility would otherwise
20 emit if, at the time construction commences, the facility is
21 scheduled to commence operation during 2016 or 2017, and at
22 least 90% of the total carbon dioxide emissions that the
23 facility would otherwise emit if, at the time construction
24 commences, the facility is scheduled to commence operation
25 after 2017. The power block of the clean coal facility shall
26 not exceed allowable emission rates for sulfur dioxide,

1 nitrogen oxides, carbon monoxide, particulates and mercury for
2 a natural gas-fired combined-cycle facility the same size as
3 and in the same location as the clean coal facility at the time
4 the clean coal facility obtains an approved air permit. All
5 coal used by a clean coal facility shall have high volatile
6 bituminous rank and greater than 1.7 pounds of sulfur per
7 million btu content, unless the clean coal facility does not
8 use gasification technology and was operating as a
9 conventional coal-fired electric generating facility on June
10 1, 2009 (the effective date of Public Act 95-1027).

11 "Clean coal SNG brownfield facility" means a facility that
12 (1) has commenced construction by July 1, 2015 on an urban
13 brownfield site in a municipality with at least 1,000,000
14 residents; (2) uses a gasification process to produce
15 substitute natural gas; (3) uses coal as at least 50% of the
16 total feedstock over the term of any sourcing agreement with a
17 utility and the remainder of the feedstock may be either
18 petroleum coke or coal, with all such coal having a high
19 bituminous rank and greater than 1.7 pounds of sulfur per
20 million Btu content unless the facility reasonably determines
21 that it is necessary to use additional petroleum coke to
22 deliver additional consumer savings, in which case the
23 facility shall use coal for at least 35% of the total feedstock
24 over the term of any sourcing agreement; and (4) captures and
25 sequesters at least 85% of the total carbon dioxide emissions
26 that the facility would otherwise emit.

1 "Clean coal SNG facility" means a facility that uses a
2 gasification process to produce substitute natural gas, that
3 sequesters at least 90% of the total carbon dioxide emissions
4 that the facility would otherwise emit, that uses at least 90%
5 coal as a feedstock, with all such coal having a high
6 bituminous rank and greater than 1.7 pounds of sulfur per
7 million btu content, and that has a valid and effective permit
8 to construct emission sources and air pollution control
9 equipment and approval with respect to the federal regulations
10 for Prevention of Significant Deterioration of Air Quality
11 (PSD) for the plant pursuant to the federal Clean Air Act;
12 provided, however, a clean coal SNG brownfield facility shall
13 not be a clean coal SNG facility.

14 "Commission" means the Illinois Commerce Commission.

15 "Community renewable generation project" means an electric
16 generating facility that:

17 (1) is powered by wind, solar thermal energy,
18 photovoltaic cells or panels, biodiesel, crops and
19 untreated and unadulterated organic waste biomass, tree
20 waste, and hydropower that does not involve new
21 construction or significant expansion of hydropower dams;

22 (2) is interconnected at the distribution system level
23 of an electric utility as defined in this Section, a
24 municipal utility as defined in this Section that owns or
25 operates electric distribution facilities, a public
26 utility as defined in Section 3-105 of the Public

1 Utilities Act, or an electric cooperative, as defined in
2 Section 3-119 of the Public Utilities Act;

3 (3) credits the value of electricity generated by the
4 facility to the subscribers of the facility; and

5 (4) is limited in nameplate capacity to less than or
6 equal to 2,000 kilowatts.

7 "Costs incurred in connection with the development and
8 construction of a facility" means:

9 (1) the cost of acquisition of all real property,
10 fixtures, and improvements in connection therewith and
11 equipment, personal property, and other property, rights,
12 and easements acquired that are deemed necessary for the
13 operation and maintenance of the facility;

14 (2) financing costs with respect to bonds, notes, and
15 other evidences of indebtedness of the Agency;

16 (3) all origination, commitment, utilization,
17 facility, placement, underwriting, syndication, credit
18 enhancement, and rating agency fees;

19 (4) engineering, design, procurement, consulting,
20 legal, accounting, title insurance, survey, appraisal,
21 escrow, trustee, collateral agency, interest rate hedging,
22 interest rate swap, capitalized interest, contingency, as
23 required by lenders, and other financing costs, and other
24 expenses for professional services; and

25 (5) the costs of plans, specifications, site study and
26 investigation, installation, surveys, other Agency costs

1 and estimates of costs, and other expenses necessary or
2 incidental to determining the feasibility of any project,
3 together with such other expenses as may be necessary or
4 incidental to the financing, insuring, acquisition, and
5 construction of a specific project and starting up,
6 commissioning, and placing that project in operation.

7 "Delivery services" has the same definition as found in
8 Section 16-102 of the Public Utilities Act.

9 "Delivery year" means the consecutive 12-month period
10 beginning June 1 of a given year and ending May 31 of the
11 following year.

12 "Department" means the Department of Commerce and Economic
13 Opportunity.

14 "Director" means the Director of the Illinois Power
15 Agency.

16 "Demand-response" means measures that decrease peak
17 electricity demand or shift demand from peak to off-peak
18 periods.

19 "Distributed renewable energy generation device" means a
20 device that is:

21 (1) powered by wind, solar thermal energy,
22 photovoltaic cells or panels, biodiesel, crops and
23 untreated and unadulterated organic waste biomass, tree
24 waste, and hydropower that does not involve new
25 construction or significant expansion of hydropower dams;

26 (2) interconnected at the distribution system level of

1 either an electric utility as defined in this Section, a
2 municipal utility as defined in this Section that owns or
3 operates electric distribution facilities, or a rural
4 electric cooperative as defined in Section 3-119 of the
5 Public Utilities Act;

6 (3) located on the customer side of the customer's
7 electric meter and is primarily used to offset that
8 customer's electricity load; and

9 (4) limited in nameplate capacity to less than or
10 equal to 2,000 kilowatts.

11 "Energy efficiency" means measures that reduce the amount
12 of electricity or natural gas consumed in order to achieve a
13 given end use. "Energy efficiency" includes voltage
14 optimization measures that optimize the voltage at points on
15 the electric distribution voltage system and thereby reduce
16 electricity consumption by electric customers' end use
17 devices. "Energy efficiency" also includes measures that
18 reduce the total Btus of electricity, natural gas, and other
19 fuels needed to meet the end use or uses. For electric
20 utilities that serve less than 3,000,000 retail customers but
21 more than 500,000 retail customers in this State, energy
22 efficiency measures that reduce the total Btus of electricity,
23 natural gas, or other fuels needed to meet the end use or uses,
24 shall include, but are not limited to, measures that educate
25 about, incentivize, encourage, or otherwise support the use of
26 electricity to power, in whole or in part, vehicles,

1 including, but not limited to, cars, trucks, buses, trains,
2 trolleys, boats, on-road or off-road vehicles, or other
3 equipment or methods of transporting goods or people, and such
4 measures shall include, but are not limited to, measures that
5 educate about, incentivize, encourage, or otherwise support
6 the adoption of electric vehicles by retail customers of all
7 customer classes.

8 "Electric utility" has the same definition as found in
9 Section 16-102 of the Public Utilities Act.

10 "Facility" means an electric generating unit or a
11 co-generating unit that produces electricity along with
12 related equipment necessary to connect the facility to an
13 electric transmission or distribution system.

14 "Governmental aggregator" means one or more units of local
15 government that individually or collectively procure
16 electricity to serve residential retail electrical loads
17 located within its or their jurisdiction.

18 "Local government" means a unit of local government as
19 defined in Section 1 of Article VII of the Illinois
20 Constitution.

21 "Municipality" means a city, village, or incorporated
22 town.

23 "Municipal utility" means a public utility owned and
24 operated by any subdivision or municipal corporation of this
25 State.

26 "Nameplate capacity" means the aggregate inverter

1 nameplate capacity in kilowatts AC.

2 "Person" means any natural person, firm, partnership,
3 corporation, either domestic or foreign, company, association,
4 limited liability company, joint stock company, or association
5 and includes any trustee, receiver, assignee, or personal
6 representative thereof.

7 "Project" means the planning, bidding, and construction of
8 a facility.

9 "Public utility" has the same definition as found in
10 Section 3-105 of the Public Utilities Act.

11 "Real property" means any interest in land together with
12 all structures, fixtures, and improvements thereon, including
13 lands under water and riparian rights, any easements,
14 covenants, licenses, leases, rights-of-way, uses, and other
15 interests, together with any liens, judgments, mortgages, or
16 other claims or security interests related to real property.

17 "Renewable energy credit" means a tradable credit that
18 represents the environmental attributes of one megawatt hour
19 of energy produced from a renewable energy resource.

20 "Renewable energy resources" includes energy and its
21 associated renewable energy credit or renewable energy credits
22 from wind, solar thermal energy, photovoltaic cells and
23 panels, biodiesel, anaerobic digestion, crops and untreated
24 and unadulterated organic waste biomass, tree waste, and
25 hydropower that does not involve new construction or
26 significant expansion of hydropower dams. For purposes of this

1 Act, landfill gas produced in the State is considered a
2 renewable energy resource. "Renewable energy resources" does
3 not include the incineration or burning of tires, garbage,
4 general household, institutional, and commercial waste,
5 industrial lunchroom or office waste, landscape waste other
6 than tree waste, railroad crossties, utility poles, or
7 construction or demolition debris, other than untreated and
8 unadulterated waste wood.

9 "Retail customer" has the same definition as found in
10 Section 16-102 of the Public Utilities Act.

11 "Revenue bond" means any bond, note, or other evidence of
12 indebtedness issued by the Authority, the principal and
13 interest of which is payable solely from revenues or income
14 derived from any project or activity of the Agency.

15 "Sequester" means permanent storage of carbon dioxide by
16 injecting it into a saline aquifer, a depleted gas reservoir,
17 or an oil reservoir, directly or through an enhanced oil
18 recovery process that may involve intermediate storage,
19 regardless of whether these activities are conducted by a
20 clean coal facility, a clean coal SNG facility, a clean coal
21 SNG brownfield facility, or a party with which a clean coal
22 facility, clean coal SNG facility, or clean coal SNG
23 brownfield facility has contracted for such purposes.

24 "Service area" has the same definition as found in Section
25 16-102 of the Public Utilities Act.

26 "Sourcing agreement" means (i) in the case of an electric

1 utility, an agreement between the owner of a clean coal
2 facility and such electric utility, which agreement shall have
3 terms and conditions meeting the requirements of paragraph (3)
4 of subsection (d) of Section 1-75, (ii) in the case of an
5 alternative retail electric supplier, an agreement between the
6 owner of a clean coal facility and such alternative retail
7 electric supplier, which agreement shall have terms and
8 conditions meeting the requirements of Section 16-115(d)(5) of
9 the Public Utilities Act, and (iii) in case of a gas utility,
10 an agreement between the owner of a clean coal SNG brownfield
11 facility and the gas utility, which agreement shall have the
12 terms and conditions meeting the requirements of subsection
13 (h-1) of Section 9-220 of the Public Utilities Act.

14 "Subscriber" means a person who (i) takes delivery service
15 from an electric utility, and (ii) has a subscription of no
16 less than 200 watts to a community renewable generation
17 project that is located in the electric utility's service
18 area. No subscriber's subscriptions may total more than 40% of
19 the nameplate capacity of an individual community renewable
20 generation project. Entities that are affiliated by virtue of
21 a common parent shall not represent multiple subscriptions
22 that total more than 40% of the nameplate capacity of an
23 individual community renewable generation project.

24 "Subscription" means an interest in a community renewable
25 generation project expressed in kilowatts, which is sized
26 primarily to offset part or all of the subscriber's

1 electricity usage.

2 "Substitute natural gas" or "SNG" means a gas manufactured
3 by gasification of hydrocarbon feedstock, which is
4 substantially interchangeable in use and distribution with
5 conventional natural gas.

6 "Total resource cost test" or "TRC test" means a standard
7 that is met if, for an investment in energy efficiency or
8 demand-response measures, the benefit-cost ratio is greater
9 than one. The benefit-cost ratio is the ratio of the net
10 present value of the total benefits of the program to the net
11 present value of the total costs as calculated over the
12 lifetime of the measures. A total resource cost test compares
13 the sum of avoided electric utility costs, representing the
14 benefits that accrue to the system and the participant in the
15 delivery of those efficiency measures and including avoided
16 costs associated with reduced use of natural gas or other
17 fuels, avoided costs associated with reduced water
18 consumption, and avoided costs associated with reduced
19 operation and maintenance costs, as well as other quantifiable
20 societal benefits, to the sum of all incremental costs of
21 end-use measures that are implemented due to the program
22 (including both utility and participant contributions), plus
23 costs to administer, deliver, and evaluate each demand-side
24 program, to quantify the net savings obtained by substituting
25 the demand-side program for supply resources. In calculating
26 avoided costs of power and energy that an electric utility

1 would otherwise have had to acquire, reasonable estimates
2 shall be included of financial costs likely to be imposed by
3 future regulations and legislation on emissions of greenhouse
4 gases. In discounting future societal costs and benefits for
5 the purpose of calculating net present values, a societal
6 discount rate based on actual, long-term Treasury bond yields
7 should be used. Notwithstanding anything to the contrary, the
8 TRC test shall not include or take into account a calculation
9 of market price suppression effects or demand reduction
10 induced price effects.

11 "Utility-scale solar project" means an electric generating
12 facility that:

- 13 (1) generates electricity using photovoltaic cells;
14 and
15 (2) has a nameplate capacity that is greater than
16 2,000 kilowatts.

17 "Utility-scale wind project" means an electric generating
18 facility that:

- 19 (1) generates electricity using wind; and
20 (2) has a nameplate capacity that is greater than
21 2,000 kilowatts.

22 "Zero emission credit" means a tradable credit that
23 represents the environmental attributes of one megawatt hour
24 of energy produced from a zero emission facility.

25 "Zero emission facility" means a facility that: (1) is
26 fueled by nuclear power; and (2) is interconnected with PJM

1 Interconnection, LLC or the Midcontinent Independent System
2 Operator, Inc., or their successors.

3 (Source: P.A. 98-90, eff. 7-15-13; 99-906, eff. 6-1-17.)

4 (20 ILCS 3855/1-75)

5 Sec. 1-75. Planning and Procurement Bureau. The Planning
6 and Procurement Bureau has the following duties and
7 responsibilities:

8 (a) The Planning and Procurement Bureau shall each year,
9 beginning in 2008, develop procurement plans and conduct
10 competitive procurement processes in accordance with the
11 requirements of Section 16-111.5 of the Public Utilities Act
12 for the eligible retail customers of electric utilities that
13 on December 31, 2005 provided electric service to at least
14 100,000 customers in Illinois. Beginning with the delivery
15 year commencing on June 1, 2017, the Planning and Procurement
16 Bureau shall develop plans and processes for the procurement
17 of zero emission credits from zero emission facilities in
18 accordance with the requirements of subsection (d-5) of this
19 Section. The Planning and Procurement Bureau shall also
20 develop procurement plans and conduct competitive procurement
21 processes in accordance with the requirements of Section
22 16-111.5 of the Public Utilities Act for the eligible retail
23 customers of small multi-jurisdictional electric utilities
24 that (i) on December 31, 2005 served less than 100,000
25 customers in Illinois and (ii) request a procurement plan for

1 their Illinois jurisdictional load. This Section shall not
2 apply to a small multi-jurisdictional utility until such time
3 as a small multi-jurisdictional utility requests the Agency to
4 prepare a procurement plan for their Illinois jurisdictional
5 load. For the purposes of this Section, the term "eligible
6 retail customers" has the same definition as found in Section
7 16-111.5(a) of the Public Utilities Act.

8 Beginning with the plan or plans to be implemented in the
9 2017 delivery year, the Agency shall no longer include the
10 procurement of renewable energy resources in the annual
11 procurement plans required by this subsection (a), except as
12 provided in subsection (q) of Section 16-111.5 of the Public
13 Utilities Act, and shall instead develop a long-term renewable
14 resources procurement plan in accordance with subsection (c)
15 of this Section and Section 16-111.5 of the Public Utilities
16 Act.

17 (1) The Agency shall each year, beginning in 2008, as
18 needed, issue a request for qualifications for experts or
19 expert consulting firms to develop the procurement plans
20 in accordance with Section 16-111.5 of the Public
21 Utilities Act. In order to qualify an expert or expert
22 consulting firm must have:

23 (A) direct previous experience assembling
24 large-scale power supply plans or portfolios for
25 end-use customers;

26 (B) an advanced degree in economics, mathematics,

1 engineering, risk management, or a related area of
2 study;

3 (C) 10 years of experience in the electricity
4 sector, including managing supply risk;

5 (D) expertise in wholesale electricity market
6 rules, including those established by the Federal
7 Energy Regulatory Commission and regional transmission
8 organizations;

9 (E) expertise in credit protocols and familiarity
10 with contract protocols;

11 (F) adequate resources to perform and fulfill the
12 required functions and responsibilities; and

13 (G) the absence of a conflict of interest and
14 inappropriate bias for or against potential bidders or
15 the affected electric utilities.

16 (2) The Agency shall each year, as needed, issue a
17 request for qualifications for a procurement administrator
18 to conduct the competitive procurement processes in
19 accordance with Section 16-111.5 of the Public Utilities
20 Act. In order to qualify an expert or expert consulting
21 firm must have:

22 (A) direct previous experience administering a
23 large-scale competitive procurement process;

24 (B) an advanced degree in economics, mathematics,
25 engineering, or a related area of study;

26 (C) 10 years of experience in the electricity

1 sector, including risk management experience;

2 (D) expertise in wholesale electricity market
3 rules, including those established by the Federal
4 Energy Regulatory Commission and regional transmission
5 organizations;

6 (E) expertise in credit and contract protocols;

7 (F) adequate resources to perform and fulfill the
8 required functions and responsibilities; and

9 (G) the absence of a conflict of interest and
10 inappropriate bias for or against potential bidders or
11 the affected electric utilities.

12 (3) The Agency shall provide affected utilities and
13 other interested parties with the lists of qualified
14 experts or expert consulting firms identified through the
15 request for qualifications processes that are under
16 consideration to develop the procurement plans and to
17 serve as the procurement administrator. The Agency shall
18 also provide each qualified expert's or expert consulting
19 firm's response to the request for qualifications. All
20 information provided under this subparagraph shall also be
21 provided to the Commission. The Agency may provide by rule
22 for fees associated with supplying the information to
23 utilities and other interested parties. These parties
24 shall, within 5 business days, notify the Agency in
25 writing if they object to any experts or expert consulting
26 firms on the lists. Objections shall be based on:

- 1 (A) failure to satisfy qualification criteria;
2 (B) identification of a conflict of interest; or
3 (C) evidence of inappropriate bias for or against
4 potential bidders or the affected utilities.

5 The Agency shall remove experts or expert consulting
6 firms from the lists within 10 days if there is a
7 reasonable basis for an objection and provide the updated
8 lists to the affected utilities and other interested
9 parties. If the Agency fails to remove an expert or expert
10 consulting firm from a list, an objecting party may seek
11 review by the Commission within 5 days thereafter by
12 filing a petition, and the Commission shall render a
13 ruling on the petition within 10 days. There is no right of
14 appeal of the Commission's ruling.

15 (4) The Agency shall issue requests for proposals to
16 the qualified experts or expert consulting firms to
17 develop a procurement plan for the affected utilities and
18 to serve as procurement administrator.

19 (5) The Agency shall select an expert or expert
20 consulting firm to develop procurement plans based on the
21 proposals submitted and shall award contracts of up to 5
22 years to those selected.

23 (6) The Agency shall select an expert or expert
24 consulting firm, with approval of the Commission, to serve
25 as procurement administrator based on the proposals
26 submitted. If the Commission rejects, within 5 days, the

1 Agency's selection, the Agency shall submit another
2 recommendation within 3 days based on the proposals
3 submitted. The Agency shall award a 5-year contract to the
4 expert or expert consulting firm so selected with
5 Commission approval.

6 (b) The experts or expert consulting firms retained by the
7 Agency shall, as appropriate, prepare procurement plans, and
8 conduct a competitive procurement process as prescribed in
9 Section 16-111.5 of the Public Utilities Act, to ensure
10 adequate, reliable, affordable, efficient, and environmentally
11 sustainable electric service at the lowest total cost over
12 time, taking into account any benefits of price stability, for
13 eligible retail customers of electric utilities that on
14 December 31, 2005 provided electric service to at least
15 100,000 customers in the State of Illinois, and for eligible
16 Illinois retail customers of small multi-jurisdictional
17 electric utilities that (i) on December 31, 2005 served less
18 than 100,000 customers in Illinois and (ii) request a
19 procurement plan for their Illinois jurisdictional load.

20 (c) Renewable portfolio standard.

21 (1) (A) The Agency shall develop a long-term renewable
22 resources procurement plan that shall include procurement
23 programs and competitive procurement events necessary to
24 meet the goals set forth in this subsection (c). The
25 initial long-term renewable resources procurement plan
26 shall be released for comment no later than 160 days after

1 June 1, 2017 (the effective date of Public Act 99-906).
2 The Agency shall review, and may revise on an expedited
3 basis, the long-term renewable resources procurement plan
4 at least every 2 years, which shall be conducted in
5 conjunction with the procurement plan under Section
6 16-111.5 of the Public Utilities Act to the extent
7 practicable to minimize administrative expense. The
8 long-term renewable resources procurement plans shall be
9 subject to review and approval by the Commission under
10 Section 16-111.5 of the Public Utilities Act.

11 (B) Subject to subparagraph (F) of this paragraph (1),
12 for electric utilities that serve more than 3,000,000
13 retail customers in this State or less than 500,000 retail
14 customers in this State, the long-term renewable resources
15 procurement plan shall include the goals for procurement
16 of renewable energy credits to meet at least the following
17 overall percentages: 13% by the 2017 delivery year;
18 increasing by at least 1.5% each delivery year thereafter
19 to at least 25% by the 2025 delivery year; and continuing
20 at no less than 25% for each delivery year thereafter and
21 for electric utilities that serve less than 3,000,000
22 retail customers but more than 500,000 retail customers in
23 this State, the long-term renewable resources procurement
24 plan shall include the goals for procurement of renewable
25 energy credits to meet at least the following overall
26 percentages: 13% by the 2017 delivery year; increasing by

1 at least 1.5% each delivery year thereafter to at least
2 25% by the 2025 delivery year, and by at least 1.5% every
3 year thereafter to at least 32.5% by the 2030 delivery
4 year; and continuing at no less than 32.5% for each
5 delivery year thereafter. In the event of a conflict
6 between these goals and the new wind and new photovoltaic
7 procurement requirements described in items (i) through
8 (iii) of subparagraph (C) of this paragraph (1), the
9 long-term plan shall prioritize compliance with the new
10 wind and new photovoltaic procurement requirements
11 described in items (i) through (iii) of subparagraph (C)
12 of this paragraph (1) over the annual percentage targets
13 described in this subparagraph (B).

14 For the delivery year beginning June 1, 2017, the
15 procurement plan shall include cost-effective renewable
16 energy resources equal to at least 13% of each utility's
17 load for eligible retail customers and 13% of the
18 applicable portion of each utility's load for retail
19 customers who are not eligible retail customers, which
20 applicable portion shall equal 50% of the utility's load
21 for retail customers who are not eligible retail customers
22 on February 28, 2017.

23 For the delivery year beginning June 1, 2018, the
24 procurement plan shall include cost-effective renewable
25 energy resources equal to at least 14.5% of each utility's
26 load for eligible retail customers and 14.5% of the

1 applicable portion of each utility's load for retail
2 customers who are not eligible retail customers, which
3 applicable portion shall equal 75% of the utility's load
4 for retail customers who are not eligible retail customers
5 on February 28, 2017.

6 For the delivery year beginning June 1, 2019, and for
7 each year thereafter, the procurement plans shall include
8 cost-effective renewable energy resources equal to a
9 minimum percentage of each utility's load for all retail
10 customers as follows: for electric utilities that serve
11 more than 3,000,000 retail customers in this State or less
12 than 500,000 retail customers in this State, 16% by June
13 1, 2019; increasing by 1.5% each year thereafter to 25% by
14 June 1, 2025; and 25% by June 1, 2026 and each year
15 thereafter and for electric utilities that serve less than
16 3,000,000 retail customers but more than 500,000 retail
17 customers in this State, 16% by June 1, 2019; increasing
18 by 1.5% each year thereafter to 32.5% by June 1, 2030; and
19 32.5% by June 1, 2031 and each year thereafter.

20 For each delivery year, the Agency shall first
21 recognize each utility's obligations for that delivery
22 year under existing contracts. Any renewable energy
23 credits under existing contracts, including renewable
24 energy credits as part of renewable energy resources,
25 shall be used to meet the goals set forth in this
26 subsection (c) for the delivery year.

1 (C) Of the renewable energy credits procured under
2 this subsection (c), at least 75% shall come from wind and
3 photovoltaic projects. The long-term renewable resources
4 procurement plan described in subparagraph (A) of this
5 paragraph (1) shall include the procurement of renewable
6 energy credits in amounts equal to at least the following:

7 (i) By the end of the 2020 delivery year:

8 At least 2,000,000 renewable energy credits
9 for each delivery year shall come from new wind
10 projects; and

11 At least 2,000,000 renewable energy credits
12 for each delivery year shall come from new
13 photovoltaic projects; of that amount, to the
14 extent possible, the Agency shall procure: at
15 least 50% from solar photovoltaic projects using
16 the program outlined in subparagraph (K) of this
17 paragraph (1) from distributed renewable energy
18 generation devices or community renewable
19 generation projects; at least 40% from
20 utility-scale solar projects; at least 2% from
21 brownfield site photovoltaic projects that are not
22 community renewable generation projects; and the
23 remainder shall be determined through the
24 long-term planning process described in
25 subparagraph (A) of this paragraph (1); however,
26 if the long-term renewable resources procurement

1 plan includes the procurement of more than
2 2,000,000 renewable energy credits from new
3 photovoltaic projects, then the foregoing
4 allocations of renewable energy credits from the
5 program outlined in subparagraph (K) of this
6 paragraph (1), utility-scale solar projects, and
7 brownfield site photovoltaic projects that are not
8 community renewable generation projects shall not
9 apply to the portion of the renewable energy
10 credits procured in excess of the 2,000,000
11 renewable energy credits procured on behalf of
12 electric utilities that serve less than 3,000,000
13 retail customers but more than 500,000 retail
14 customers in this State and the allocation of such
15 procurement on behalf of electric utilities that
16 serve less than 3,000,000 retail customers but
17 more than 500,000 retail customers in this State
18 shall instead be based on the mix that produces
19 the lowest cost for the renewable energy credits
20 procured.

21 (ii) By the end of the 2025 delivery year:

22 At least 3,000,000 renewable energy credits
23 for each delivery year shall come from new wind
24 projects; and

25 At least 3,000,000 renewable energy credits
26 for each delivery year shall come from new

1 photovoltaic projects; of that amount, to the
2 extent possible, the Agency shall procure: at
3 least 50% from solar photovoltaic projects using
4 the program outlined in subparagraph (K) of this
5 paragraph (1) from distributed renewable energy
6 devices or community renewable generation
7 projects; at least 40% from utility-scale solar
8 projects; at least 2% from brownfield site
9 photovoltaic projects that are not community
10 renewable generation projects; and the remainder
11 shall be determined through the long-term planning
12 process described in subparagraph (A) of this
13 paragraph (1); however, if the long-term renewable
14 resources procurement plan includes the
15 procurement of more than 3,000,000 renewable
16 energy credits from new photovoltaic projects,
17 then the foregoing allocations of renewable energy
18 credits from the program outlined in subparagraph
19 (K) of this paragraph (1), utility-scale solar
20 projects, and brownfield site photovoltaic
21 projects that are not community renewable
22 generation projects shall not apply to the portion
23 of the renewable energy credits procured in excess
24 of the 3,000,000 renewable energy credits procured
25 on behalf of electric utilities that serve less
26 than 3,000,000 retail customers but more than

1 500,000 retail customers in this State and the
2 allocation of such procurement on behalf of
3 electric utilities that serve less than 3,000,000
4 retail customers but more than 500,000 retail
5 customers in this State shall instead be based on
6 the mix that produced the lowest cost for the
7 renewable energy credits procured.

8 (iii) By the end of the 2030 delivery year:

9 At least 4,000,000 renewable energy credits
10 for each delivery year shall come from new wind
11 projects; and

12 At least 4,000,000 renewable energy credits
13 for each delivery year shall come from new
14 photovoltaic projects; of that amount, to the
15 extent possible, the Agency shall procure: at
16 least 50% from solar photovoltaic projects using
17 the program outlined in subparagraph (K) of this
18 paragraph (1) from distributed renewable energy
19 devices or community renewable generation
20 projects; at least 40% from utility-scale solar
21 projects; at least 2% from brownfield site
22 photovoltaic projects that are not community
23 renewable generation projects; and the remainder
24 shall be determined through the long-term planning
25 process described in subparagraph (A) of this
26 paragraph (1); however, if the long-term renewable

1 resources procurement plan includes the
2 procurement of more than 4,000,000 renewable
3 energy credits from new photovoltaic projects,
4 then the foregoing allocations of renewable energy
5 credits from the program outlined in subparagraph
6 (K) of this paragraph (1), utility-scale solar
7 projects, and brownfield site photovoltaic
8 projects that are not community renewable
9 generation projects shall not apply to the portion
10 of the renewable energy credits procured in excess
11 of the 4,000,000 renewable energy credits procured
12 on behalf of electric utilities that serve less
13 than 3,000,000 retail customers but more than
14 500,000 retail customers in this State and the
15 allocation of such procurement on behalf of
16 electric utilities that serve less than 3,000,000
17 retail customers but more than 500,000 retail
18 customers in this State shall instead be based on
19 the mix that produced the lowest cost for the
20 renewable energy credits procured.

21 For purposes of this Section:

22 "New wind projects" means wind renewable
23 energy facilities that are energized after June 1,
24 2017 for the delivery year commencing June 1, 2017
25 or within 3 years after the date the Commission
26 approves contracts for subsequent delivery years.

1 "New photovoltaic projects" means photovoltaic
2 renewable energy facilities that are energized
3 after June 1, 2017. Photovoltaic projects
4 developed under Section 1-56 of this Act shall not
5 apply towards the new photovoltaic project
6 requirements in this subparagraph (C).

7 (D) Renewable energy credits shall be cost effective.
8 For purposes of this subsection (c), "cost effective"
9 means that the costs of procuring renewable energy
10 resources do not cause the limit stated in subparagraph
11 (E) of this paragraph (1) to be exceeded and, for
12 renewable energy credits procured through a competitive
13 procurement event, do not exceed benchmarks based on
14 market prices for like products in the region. For
15 purposes of this subsection (c), "like products" means
16 contracts for renewable energy credits from the same or
17 substantially similar technology, same or substantially
18 similar vintage (new or existing), the same or
19 substantially similar quantity, and the same or
20 substantially similar contract length and structure.
21 Benchmarks shall be developed by the procurement
22 administrator, in consultation with the Commission staff,
23 Agency staff, and the procurement monitor and shall be
24 subject to Commission review and approval. If price
25 benchmarks for like products in the region are not
26 available, the procurement administrator shall establish

1 price benchmarks based on publicly available data on
2 regional technology costs and expected current and future
3 regional energy prices. The benchmarks in this Section
4 shall not be used to curtail or otherwise reduce
5 contractual obligations entered into by or through the
6 Agency prior to June 1, 2017 (the effective date of Public
7 Act 99-906).

8 (E) For purposes of this subsection (c), the required
9 procurement of cost-effective renewable energy resources
10 for a particular year commencing prior to June 1, 2017
11 shall be measured as a percentage of the actual amount of
12 electricity (megawatt-hours) supplied by the electric
13 utility to eligible retail customers in the delivery year
14 ending immediately prior to the procurement, and, for
15 delivery years commencing on and after June 1, 2017, the
16 required procurement of cost-effective renewable energy
17 resources for a particular year shall be measured as a
18 percentage of the actual amount of electricity
19 (megawatt-hours) delivered by the electric utility in the
20 delivery year ending immediately prior to the procurement,
21 to all retail customers in its service territory. For
22 purposes of this subsection (c), the amount paid per
23 kilowatthour means the total amount paid for electric
24 service expressed on a per kilowatthour basis. For
25 purposes of this subsection (c), the total amount paid for
26 electric service includes without limitation amounts paid

1 for supply, transmission, distribution, surcharges, and
2 add-on taxes.

3 Notwithstanding the requirements of this subsection
4 (c), the total of renewable energy resources procured
5 under the procurement plan for any single year shall be
6 subject to the limitations of this subparagraph (E). Such
7 procurement shall be reduced for all retail customers
8 based on the amount necessary to limit the annual
9 estimated average net increase due to the costs of these
10 resources included in the amounts paid by eligible retail
11 customers in connection with electric service to no more
12 than the greater of 2.015% of the amount paid per
13 kilowatthour by those customers during the year ending May
14 31, 2007 or the incremental amount per kilowatthour paid
15 for these resources in 2011; however, procurements that
16 occur for procurement periods that begin on or after June
17 1, 2026 shall be reduced for all retail customers of
18 electric utilities that serve less than 3,000,000 retail
19 customers but more than 500,000 retail customers in this
20 State only by an amount necessary to limit the annual
21 estimated average net increase due to the costs of these
22 resources included in the amounts paid by eligible retail
23 customers in connection with electric service to no more
24 than the greater of 2.515% of the amount paid per
25 kilowatthour by those customers during the year ending May
26 31, 2007 or the incremental amount per kilowatthour paid

1 for these resources in 2011. To arrive at a maximum dollar
2 amount of renewable energy resources to be procured for
3 the particular delivery year, the resulting per
4 kilowatthour amount shall be applied to the actual amount
5 of kilowatthours of electricity delivered, or applicable
6 portion of such amount as specified in paragraph (1) of
7 this subsection (c), as applicable, by the electric
8 utility in the delivery year immediately prior to the
9 procurement to all retail customers in its service
10 territory. The calculations required by this subparagraph
11 (E) shall be made only once for each delivery year at the
12 time that the renewable energy resources are procured.
13 Once the determination as to the amount of renewable
14 energy resources to procure is made based on the
15 calculations set forth in this subparagraph (E) and the
16 contracts procuring those amounts are executed, no
17 subsequent rate impact determinations shall be made and no
18 adjustments to those contract amounts shall be allowed.
19 All costs incurred under such contracts shall be fully
20 recoverable by the electric utility as provided in this
21 Section.

22 (F) If the limitation on the amount of renewable
23 energy resources procured in subparagraph (E) of this
24 paragraph (1) prevents the Agency from meeting all of the
25 goals in this subsection (c), the Agency's long-term plan
26 shall prioritize compliance with the requirements of this

1 subsection (c) regarding renewable energy credits in the
2 following order:

3 (i) renewable energy credits under existing
4 contractual obligations;

5 (i-5) funding for the Illinois Solar for All
6 Program, as described in subparagraph (O) of this
7 paragraph (1);

8 (ii) renewable energy credits necessary to comply
9 with the new wind and new photovoltaic procurement
10 requirements described in items (i) through (iii) of
11 subparagraph (C) of this paragraph (1); and

12 (iii) renewable energy credits necessary to meet
13 the remaining requirements of this subsection (c).

14 (G) The following provisions shall apply to the
15 Agency's procurement of renewable energy credits under
16 this subsection (c):

17 (i) Notwithstanding whether a long-term renewable
18 resources procurement plan has been approved, the
19 Agency shall conduct an initial forward procurement
20 for renewable energy credits from new utility-scale
21 wind projects within 160 days after June 1, 2017 (the
22 effective date of Public Act 99-906). For the purposes
23 of this initial forward procurement, the Agency shall
24 solicit 15-year contracts for delivery of 1,000,000
25 renewable energy credits delivered annually from new
26 utility-scale wind projects to begin delivery on June

1 1, 2019, if available, but not later than June 1, 2021,
2 unless the project has delays in the establishment of
3 an operating interconnection with the applicable
4 transmission or distribution system as a result of the
5 actions or inactions of the transmission or
6 distribution provider, or other causes for force
7 majeure as outlined in the procurement contract, in
8 which case, not later than June 1, 2022. Payments to
9 suppliers of renewable energy credits shall commence
10 upon delivery. Renewable energy credits procured under
11 this initial procurement shall be included in the
12 Agency's long-term plan and shall apply to all
13 renewable energy goals in this subsection (c).

14 (ii) Notwithstanding whether a long-term renewable
15 resources procurement plan has been approved, the
16 Agency shall conduct an initial forward procurement
17 for renewable energy credits from new utility-scale
18 solar projects and brownfield site photovoltaic
19 projects within one year after June 1, 2017 (the
20 effective date of Public Act 99-906). For the purposes
21 of this initial forward procurement, the Agency shall
22 solicit 15-year contracts for delivery of 1,000,000
23 renewable energy credits delivered annually from new
24 utility-scale solar projects and brownfield site
25 photovoltaic projects to begin delivery on June 1,
26 2019, if available, but not later than June 1, 2021,

1 unless the project has delays in the establishment of
2 an operating interconnection with the applicable
3 transmission or distribution system as a result of the
4 actions or inactions of the transmission or
5 distribution provider, or other causes for force
6 majeure as outlined in the procurement contract, in
7 which case, not later than June 1, 2022. The Agency may
8 structure this initial procurement in one or more
9 discrete procurement events. Payments to suppliers of
10 renewable energy credits shall commence upon delivery.
11 Renewable energy credits procured under this initial
12 procurement shall be included in the Agency's
13 long-term plan and shall apply to all renewable energy
14 goals in this subsection (c).

15 (iii) Subsequent forward procurements for
16 utility-scale wind projects shall solicit at least
17 1,000,000 renewable energy credits delivered annually
18 per procurement event and shall be planned, scheduled,
19 and designed such that the cumulative amount of
20 renewable energy credits delivered from all new wind
21 projects in each delivery year shall not exceed the
22 Agency's projection of the cumulative amount of
23 renewable energy credits that will be delivered from
24 all new photovoltaic projects, including utility-scale
25 and distributed photovoltaic devices, in the same
26 delivery year at the time scheduled for wind contract

1 delivery.

2 (iv) If, at any time after the time set for
3 delivery of renewable energy credits pursuant to the
4 initial procurements in items (i) and (ii) of this
5 subparagraph (G), the cumulative amount of renewable
6 energy credits projected to be delivered from all new
7 wind projects in a given delivery year exceeds the
8 cumulative amount of renewable energy credits
9 projected to be delivered from all new photovoltaic
10 projects in that delivery year by 200,000 or more
11 renewable energy credits, then the Agency shall within
12 60 days adjust the procurement programs in the
13 long-term renewable resources procurement plan to
14 ensure that the projected cumulative amount of
15 renewable energy credits to be delivered from all new
16 wind projects does not exceed the projected cumulative
17 amount of renewable energy credits to be delivered
18 from all new photovoltaic projects by 200,000 or more
19 renewable energy credits, provided that nothing in
20 this Section shall preclude the projected cumulative
21 amount of renewable energy credits to be delivered
22 from all new photovoltaic projects from exceeding the
23 projected cumulative amount of renewable energy
24 credits to be delivered from all new wind projects in
25 each delivery year and provided further that nothing
26 in this item (iv) shall require the curtailment of an

1 executed contract. The Agency shall update, on a
2 quarterly basis, its projection of the renewable
3 energy credits to be delivered from all projects in
4 each delivery year. Notwithstanding anything to the
5 contrary, the Agency may adjust the timing of
6 procurement events conducted under this subparagraph
7 (G). The long-term renewable resources procurement
8 plan shall set forth the process by which the
9 adjustments may be made.

10 (v) All procurements under this subparagraph (G)
11 shall comply with the geographic requirements in
12 subparagraph (I) of this paragraph (1) and shall
13 follow the procurement processes and procedures
14 described in this Section and Section 16-111.5 of the
15 Public Utilities Act to the extent practicable, and
16 these processes and procedures may be expedited to
17 accommodate the schedule established by this
18 subparagraph (G).

19 (H) The procurement of renewable energy resources for
20 a given delivery year shall be reduced as described in
21 this subparagraph (H) if an alternative retail electric
22 supplier meets the requirements described in this
23 subparagraph (H).

24 (i) Within 45 days after June 1, 2017 (the
25 effective date of Public Act 99-906), an alternative
26 retail electric supplier or its successor shall submit

1 an informational filing to the Illinois Commerce
2 Commission certifying that, as of December 31, 2015,
3 the alternative retail electric supplier owned one or
4 more electric generating facilities that generates
5 renewable energy resources as defined in Section 1-10
6 of this Act, provided that such facilities are not
7 powered by wind or photovoltaics, and the facilities
8 generate one renewable energy credit for each
9 megawatthour of energy produced from the facility.

10 The informational filing shall identify each
11 facility that was eligible to satisfy the alternative
12 retail electric supplier's obligations under Section
13 16-115D of the Public Utilities Act as described in
14 this item (i).

15 (ii) For a given delivery year, the alternative
16 retail electric supplier may elect to supply its
17 retail customers with renewable energy credits from
18 the facility or facilities described in item (i) of
19 this subparagraph (H) that continue to be owned by the
20 alternative retail electric supplier.

21 (iii) The alternative retail electric supplier
22 shall notify the Agency and the applicable utility, no
23 later than February 28 of the year preceding the
24 applicable delivery year or 15 days after June 1, 2017
25 (the effective date of Public Act 99-906), whichever
26 is later, of its election under item (ii) of this

1 subparagraph (H) to supply renewable energy credits to
2 retail customers of the utility. Such election shall
3 identify the amount of renewable energy credits to be
4 supplied by the alternative retail electric supplier
5 to the utility's retail customers and the source of
6 the renewable energy credits identified in the
7 informational filing as described in item (i) of this
8 subparagraph (H), subject to the following
9 limitations:

10 For the delivery year beginning June 1, 2018,
11 the maximum amount of renewable energy credits to
12 be supplied by an alternative retail electric
13 supplier under this subparagraph (H) shall be 68%
14 multiplied by 25% multiplied by 14.5% multiplied
15 by the amount of metered electricity
16 (megawatt-hours) delivered by the alternative
17 retail electric supplier to Illinois retail
18 customers during the delivery year ending May 31,
19 2016.

20 For delivery years beginning June 1, 2019 and
21 each year thereafter, the maximum amount of
22 renewable energy credits to be supplied by an
23 alternative retail electric supplier under this
24 subparagraph (H) shall be 68% multiplied by 50%
25 multiplied by 16% multiplied by the amount of
26 metered electricity (megawatt-hours) delivered by

1 the alternative retail electric supplier to
2 Illinois retail customers during the delivery year
3 ending May 31, 2016, provided that the 16% value
4 shall increase by 1.5% each delivery year
5 thereafter to 25% by the delivery year beginning
6 June 1, 2025, and thereafter the 25% value shall
7 apply to each delivery year.

8 For each delivery year, the total amount of
9 renewable energy credits supplied by all alternative
10 retail electric suppliers under this subparagraph (H)
11 shall not exceed 9% of the Illinois target renewable
12 energy credit quantity. The Illinois target renewable
13 energy credit quantity for the delivery year beginning
14 June 1, 2018 is 14.5% multiplied by the total amount of
15 metered electricity (megawatt-hours) delivered in the
16 delivery year immediately preceding that delivery
17 year, provided that the 14.5% shall increase by 1.5%
18 each delivery year thereafter to 25% by the delivery
19 year beginning June 1, 2025, and thereafter the 25%
20 value shall apply to each delivery year.

21 If the requirements set forth in items (i) through
22 (iii) of this subparagraph (H) are met, the charges
23 that would otherwise be applicable to the retail
24 customers of the alternative retail electric supplier
25 under paragraph (6) of this subsection (c) for the
26 applicable delivery year shall be reduced by the ratio

1 of the quantity of renewable energy credits supplied
2 by the alternative retail electric supplier compared
3 to that supplier's target renewable energy credit
4 quantity. The supplier's target renewable energy
5 credit quantity for the delivery year beginning June
6 1, 2018 is 14.5% multiplied by the total amount of
7 metered electricity (megawatt-hours) delivered by the
8 alternative retail supplier in that delivery year,
9 provided that the 14.5% shall increase by 1.5% each
10 delivery year thereafter to 25% by the delivery year
11 beginning June 1, 2025, and thereafter the 25% value
12 shall apply to each delivery year.

13 On or before April 1 of each year, the Agency shall
14 annually publish a report on its website that
15 identifies the aggregate amount of renewable energy
16 credits supplied by alternative retail electric
17 suppliers under this subparagraph (H).

18 (I) The Agency shall design its long-term renewable
19 energy procurement plan to maximize the State's interest
20 in the health, safety, and welfare of its residents,
21 including but not limited to minimizing sulfur dioxide,
22 nitrogen oxide, particulate matter and other pollution
23 that adversely affects public health in this State,
24 increasing fuel and resource diversity in this State,
25 enhancing the reliability and resiliency of the
26 electricity distribution system in this State, meeting

1 goals to limit carbon dioxide emissions under federal or
2 State law, and contributing to a cleaner and healthier
3 environment for the citizens of this State, while
4 balancing these goals with the requirement to minimize the
5 cost to customers attributable to the procurement of
6 renewable energy credits set forth in subparagraph (C) of
7 paragraph (1) of this subsection (c). In order to further
8 these legislative purposes, renewable energy credits shall
9 be eligible to be counted toward the renewable energy
10 requirements of this subsection (c) if they are generated
11 from facilities located in this State. The Agency may
12 qualify renewable energy credits from facilities located
13 in states adjacent to Illinois if the generator
14 demonstrates and the Agency determines that the operation
15 of such facility or facilities will help promote the
16 State's interest in the health, safety, and welfare of its
17 residents based on the public interest criteria described
18 above. To ensure that the public interest criteria are
19 applied to the procurement and given full effect, the
20 Agency's long-term procurement plan shall describe in
21 detail how each public interest factor shall be considered
22 and weighted for facilities located in states adjacent to
23 Illinois.

24 (J) In order to promote the competitive development of
25 renewable energy resources in furtherance of the State's
26 interest in the health, safety, and welfare of its

1 residents, renewable energy credits shall not be eligible
2 to be counted toward the renewable energy requirements of
3 this subsection (c) if they are sourced from a generating
4 unit whose costs were being recovered through rates
5 regulated by this State or any other state or states on or
6 after January 1, 2017. Each contract executed to purchase
7 renewable energy credits under this subsection (c) shall
8 provide for the contract's termination if the costs of the
9 generating unit supplying the renewable energy credits
10 subsequently begin to be recovered through rates regulated
11 by this State or any other state or states; and each
12 contract shall further provide that, in that event, the
13 supplier of the credits must return 110% of all payments
14 received under the contract. Amounts returned under the
15 requirements of this subparagraph (J) shall be retained by
16 the utility and all of these amounts shall be used for the
17 procurement of additional renewable energy credits from
18 new wind or new photovoltaic resources as defined in this
19 subsection (c). The long-term plan shall provide that
20 these renewable energy credits shall be procured in the
21 next procurement event.

22 Notwithstanding the limitations of this subparagraph
23 (J), renewable energy credits sourced from generating
24 units that are constructed, purchased, owned, or leased by
25 an electric utility as part of an approved project,
26 program, or pilot under Section 1-56 of this Act shall be

1 eligible to be counted toward the renewable energy
2 requirements of this subsection (c), regardless of how the
3 costs of these units are recovered.

4 (K) The long-term renewable resources procurement plan
5 developed by the Agency in accordance with subparagraph
6 (A) of this paragraph (1) shall include an Adjustable
7 Block program for the procurement of renewable energy
8 credits from new photovoltaic projects that are
9 distributed renewable energy generation devices or new
10 photovoltaic community renewable generation projects on
11 behalf of electric utilities that serve more than
12 3,000,000 retail customers or less than 500,000 retail
13 customers in this State and a competitive procurement
14 process for the procurement of new photovoltaic community
15 renewable generation projects on behalf of electric
16 utilities that serve less than 3,000,000 retail customers
17 but more than 500,000 retail customers in this State. The

18 Adjustable Block program shall be designed to provide a
19 transparent schedule of prices and quantities to enable
20 the photovoltaic market to scale up and for renewable
21 energy credit prices to adjust at a predictable rate over
22 time. The prices set by the Adjustable Block program can
23 be reflected as a set value or as the product of a formula.

24 The Adjustable Block program shall include for each
25 category of eligible projects: a schedule of standard
26 block purchase prices to be offered; a series of steps,

1 with associated nameplate capacity and purchase prices
2 that adjust from step to step; and automatic opening of
3 the next step as soon as the nameplate capacity and
4 available purchase prices for an open step are fully
5 committed or reserved. Only projects energized on or after
6 June 1, 2017 shall be eligible for the Adjustable Block
7 program. For each block group the Agency shall determine
8 the number of blocks, the amount of generation capacity in
9 each block, and the purchase price for each block,
10 provided that the purchase price provided and the total
11 amount of generation in all blocks for all block groups
12 shall be sufficient to meet the goals in this subsection
13 (c). The Agency may periodically review its prior
14 decisions establishing the number of blocks, the amount of
15 generation capacity in each block, and the purchase price
16 for each block, and may propose, on an expedited basis,
17 changes to these previously set values, including but not
18 limited to redistributing these amounts and the available
19 funds as necessary and appropriate, subject to Commission
20 approval as part of the periodic plan revision process
21 described in Section 16-111.5 of the Public Utilities Act.
22 The Agency may define different block sizes, purchase
23 prices, or other distinct terms and conditions for
24 projects located in different utility service territories
25 if the Agency deems it necessary to meet the goals in this
26 subsection (c); however, if, for any block to be procured

1 on behalf of electric utilities that serve less than
2 3,000,000 retail customers but more than 500,000 retail
3 customers in this State, the quantity of renewable energy
4 credits sought by eligible projects exceeds the quantity
5 of renewable energy credits defined by the Agency for the
6 block, the Agency shall lower the price applicable to the
7 block and require eligible projects to affirm the
8 commitment to the quantity of renewable energy credits
9 sought. The Agency shall employ a stepped process of
10 lowering the price applicable to the block so as to
11 identify a price at which the quantity of renewable energy
12 credits sought by eligible projects balances with the
13 renewable energy credits sought by the Agency for the
14 block.

15 The competitive procurement process used for the
16 procurement of new photovoltaic community renewable
17 generation projects on behalf of electric utilities that
18 serve less than 3,000,000 retail customers but more than
19 500,000 retail customers in this State shall define the
20 quantity of renewable energy credits to be procured and
21 allow bidders to submit price offers to the Agency. The
22 Agency shall conduct the competitive procurement process
23 in a manner that results in the lowest cost for the
24 renewable energy credits procured.

25 The Adjustable Block program and competitive
26 procurement process shall include at least the following

1 block groups in at least the following amounts, which may
2 be adjusted upon review by the Agency and approval by the
3 Commission as described in this subparagraph (K):

4 (i) At least 25% from distributed renewable energy
5 generation devices with a nameplate capacity of no
6 more than 10 kilowatts.

7 (ii) At least 25% from distributed renewable
8 energy generation devices with a nameplate capacity of
9 more than 10 kilowatts and no more than 2,000
10 kilowatts. The Agency may create sub-categories within
11 this category to account for the differences between
12 projects for small commercial customers, large
13 commercial customers, and public or non-profit
14 customers.

15 (iii) At least 25% from photovoltaic community
16 renewable generation projects.

17 (iv) The remaining 25% shall be allocated as
18 specified by the Agency in the long-term renewable
19 resources procurement plan.

20 The Adjustable Block program shall be designed to
21 ensure that renewable energy credits are procured from
22 photovoltaic distributed renewable energy generation
23 devices and new photovoltaic community renewable energy
24 generation projects in diverse locations and are not
25 concentrated in a few geographic areas.

26 (L) The procurement of photovoltaic renewable energy

1 credits under items (i) through (iv) of subparagraph (K)
2 of this paragraph (1) shall be subject to the following
3 contract and payment terms:

4 (i) The Agency shall procure contracts of at least
5 15 years in length.

6 (ii) For those renewable energy credits that
7 qualify and are procured under item (i) of
8 subparagraph (K) of this paragraph (1), the renewable
9 energy credit purchase price shall be paid in full by
10 the contracting utilities at the time that the
11 facility producing the renewable energy credits is
12 interconnected at the distribution system level of the
13 utility and energized. The electric utility shall
14 receive and retire all renewable energy credits
15 generated by the project for the first 15 years of
16 operation.

17 (iii) For those renewable energy credits that
18 qualify and are procured under item (ii) and (iii) of
19 subparagraph (K) of this paragraph (1) and any
20 additional categories of distributed generation
21 included in the long-term renewable resources
22 procurement plan and approved by the Commission, 20
23 percent of the renewable energy credit purchase price
24 shall be paid by the contracting utilities at the time
25 that the facility producing the renewable energy
26 credits is interconnected at the distribution system

1 level of the utility and energized. The remaining
2 portion shall be paid ratably over the subsequent
3 4-year period. The electric utility shall receive and
4 retire all renewable energy credits generated by the
5 project for the first 15 years of operation.

6 (iv) Each contract shall include provisions to
7 ensure the delivery of the renewable energy credits
8 for the full term of the contract.

9 (v) The utility shall be the counterparty to the
10 contracts executed under this subparagraph (L) that
11 are approved by the Commission under the process
12 described in Section 16-111.5 of the Public Utilities
13 Act. No contract shall be executed for an amount that
14 is less than one renewable energy credit per year.

15 (vi) If, at any time, approved applications for
16 the Adjustable Block program exceed funds collected by
17 the electric utility or would cause the Agency to
18 exceed the limitation described in subparagraph (E) of
19 this paragraph (1) on the amount of renewable energy
20 resources that may be procured, then the Agency shall
21 consider future uncommitted funds to be reserved for
22 these contracts on a first-come, first-served basis,
23 with the delivery of renewable energy credits required
24 beginning at the time that the reserved funds become
25 available.

26 (vii) Nothing in this Section shall require the

1 utility to advance any payment or pay any amounts that
2 exceed the actual amount of revenues collected by the
3 utility under paragraph (6) of this subsection (c) and
4 subsection (k) of Section 16-108 of the Public
5 Utilities Act, and contracts executed under this
6 Section shall expressly incorporate this limitation.

7 (M) The Agency shall be authorized to retain one or
8 more experts or expert consulting firms to develop,
9 administer, implement, operate, and evaluate the
10 Adjustable Block program described in subparagraph (K) of
11 this paragraph (1), and the Agency shall retain the
12 consultant or consultants in the same manner, to the
13 extent practicable, as the Agency retains others to
14 administer provisions of this Act, including, but not
15 limited to, the procurement administrator. The selection
16 of experts and expert consulting firms and the procurement
17 process described in this subparagraph (M) are exempt from
18 the requirements of Section 20-10 of the Illinois
19 Procurement Code, under Section 20-10 of that Code. The
20 Agency shall strive to minimize administrative expenses in
21 the implementation of the Adjustable Block program.

22 The Agency and its consultant or consultants shall
23 monitor block activity, share program activity with
24 stakeholders and conduct regularly scheduled meetings to
25 discuss program activity and market conditions. If
26 necessary, the Agency may make prospective administrative

1 adjustments to the Adjustable Block program design, such
2 as redistributing available funds or making adjustments to
3 purchase prices as necessary to achieve the goals of this
4 subsection (c). Program modifications to any price,
5 capacity block, or other program element that do not
6 deviate from the Commission's approved value by more than
7 25% shall take effect immediately and are not subject to
8 Commission review and approval. Program modifications to
9 any price, capacity block, or other program element that
10 deviate more than 25% from the Commission's approved value
11 must be approved by the Commission as a long-term plan
12 amendment under Section 16-111.5 of the Public Utilities
13 Act. The Agency shall consider stakeholder feedback when
14 making adjustments to the Adjustable Block design and
15 shall notify stakeholders in advance of any planned
16 changes.

17 (N) The long-term renewable resources procurement plan
18 required by this subsection (c) shall include a community
19 renewable generation program. The Agency shall establish
20 the terms, conditions, and program requirements for
21 community renewable generation projects with a goal to
22 expand renewable energy generating facility access to a
23 broader group of energy consumers, to ensure robust
24 participation opportunities for residential and small
25 commercial customers and those who cannot install
26 renewable energy on their own properties. Any plan

1 approved by the Commission shall allow subscriptions to
2 community renewable generation projects to be portable and
3 transferable. For purposes of this subparagraph (N),
4 "portable" means that subscriptions may be retained by the
5 subscriber even if the subscriber relocates or changes its
6 address within the same utility service territory; and
7 "transferable" means that a subscriber may assign or sell
8 subscriptions to another person within the same utility
9 service territory.

10 Electric utilities shall provide a monetary credit to
11 a subscriber's subsequent bill for service for the
12 proportional output of a community renewable generation
13 project attributable to that subscriber as specified in
14 Section 16-107.5 of the Public Utilities Act.

15 The Agency shall purchase renewable energy credits
16 from subscribed shares of photovoltaic community renewable
17 generation projects through the Adjustable Block program
18 and the competitive procurement process described in
19 subparagraph (K) of this paragraph (1) or through the
20 Illinois Solar for All Program described in Section 1-56
21 of this Act. The electric utility shall purchase any
22 unsubscribed energy from community renewable generation
23 projects that are Qualifying Facilities ("QF") under the
24 electric utility's tariff for purchasing the output from
25 QFs under Public Utilities Regulatory Policies Act of
26 1978.

1 The owners of and any subscribers to a community
2 renewable generation project shall not be considered
3 public utilities or alternative retail electricity
4 suppliers under the Public Utilities Act solely as a
5 result of their interest in or subscription to a community
6 renewable generation project and shall not be required to
7 become an alternative retail electric supplier by
8 participating in a community renewable generation project
9 with a public utility.

10 (O) For the delivery year beginning June 1, 2018, the
11 long-term renewable resources procurement plan required by
12 this subsection (c) shall provide for the Agency to
13 procure contracts to continue offering the Illinois Solar
14 for All Program described in subsection (b) of Section
15 1-56 of this Act, and the contracts approved by the
16 Commission shall be executed by the utilities that are
17 subject to this subsection (c). The long-term renewable
18 resources procurement plan shall allocate 5% of the funds
19 available under the plan for the applicable delivery year,
20 or \$10,000,000 per delivery year, whichever is greater, to
21 fund the programs, and the plan shall determine the amount
22 of funding to be apportioned to the programs identified in
23 subsection (b) of Section 1-56 of this Act; provided that
24 for the delivery years beginning June 1, 2017, June 1,
25 2021, and June 1, 2025, the long-term renewable resources
26 procurement plan shall allocate 10% of the funds available

1 under the plan for the applicable delivery year, or
2 \$20,000,000 per delivery year, whichever is greater, and
3 \$10,000,000 of such funds in such year shall be used by an
4 electric utility that serves more than 3,000,000 retail
5 customers in the State to implement a Commission-approved
6 plan under Section 16-108.12 of the Public Utilities Act.
7 In making the determinations required under this
8 subparagraph (O), the Commission shall consider the
9 experience and performance under the programs and any
10 evaluation reports. The Commission shall also provide for
11 an independent evaluation of those programs on a periodic
12 basis that are funded under this subparagraph (O).

13 (2) (Blank).

14 (3) (Blank).

15 (4) The electric utility shall retire all renewable
16 energy credits used to comply with the standard.

17 (5) Beginning with the 2010 delivery year and ending
18 June 1, 2017, an electric utility subject to this
19 subsection (c) shall apply the lesser of the maximum
20 alternative compliance payment rate or the most recent
21 estimated alternative compliance payment rate for its
22 service territory for the corresponding compliance period,
23 established pursuant to subsection (d) of Section 16-115D
24 of the Public Utilities Act to its retail customers that
25 take service pursuant to the electric utility's hourly
26 pricing tariff or tariffs. The electric utility shall

1 retain all amounts collected as a result of the
2 application of the alternative compliance payment rate or
3 rates to such customers, and, beginning in 2011, the
4 utility shall include in the information provided under
5 item (1) of subsection (d) of Section 16-111.5 of the
6 Public Utilities Act the amounts collected under the
7 alternative compliance payment rate or rates for the prior
8 year ending May 31. Notwithstanding any limitation on the
9 procurement of renewable energy resources imposed by item
10 (2) of this subsection (c), the Agency shall increase its
11 spending on the purchase of renewable energy resources to
12 be procured by the electric utility for the next plan year
13 by an amount equal to the amounts collected by the utility
14 under the alternative compliance payment rate or rates in
15 the prior year ending May 31.

16 (6) The electric utility shall be entitled to recover
17 all of its costs associated with the procurement of
18 renewable energy credits under plans approved under this
19 Section and Section 16-111.5 of the Public Utilities Act.
20 These costs shall include associated reasonable expenses
21 for implementing the procurement programs, including, but
22 not limited to, the costs of administering and evaluating
23 the Adjustable Block program, through an automatic
24 adjustment clause tariff in accordance with subsection (k)
25 of Section 16-108 of the Public Utilities Act.

26 (7) Renewable energy credits procured from new

1 photovoltaic projects or new distributed renewable energy
2 generation devices under this Section after June 1, 2017
3 (the effective date of Public Act 99-906) must be procured
4 from devices installed by a qualified person in compliance
5 with the requirements of Section 16-128A of the Public
6 Utilities Act and any rules or regulations adopted
7 thereunder.

8 In meeting the renewable energy requirements of this
9 subsection (c), to the extent feasible and consistent with
10 State and federal law, the renewable energy credit
11 procurements, Adjustable Block solar program, and
12 community renewable generation program shall provide
13 employment opportunities for all segments of the
14 population and workforce, including minority-owned and
15 woman-owned ~~female-owned~~ business enterprises, and shall
16 not, consistent with State and federal law, discriminate
17 based on race or socioeconomic status.

18 As part of any renewable resources procurement plan
19 required by this subsection (c), the Agency will compile
20 and publish a list of any seller of renewable energy
21 resources procured by the Agency that is not, as of
22 January 1 of the calendar year in which the procurement
23 plan will be filed for approval with the Commission, in
24 compliance with the reporting obligations of Section 5-117
25 of the Public Utilities Act, and the Agency shall not
26 procure any renewable energy resources from any entity not

1 in compliance with the reporting obligations of Section
2 5-117 of the Public Utilities Act in the procurement plan.

3 Any entity that submits a bid to provide renewable
4 energy resources in any procurement event conducted
5 pursuant to this Section occurring after the effective
6 date of this amendatory Act of the 102nd General Assembly
7 shall certify that not less than the prevailing wage, as
8 determined pursuant to the Prevailing Wage Act, was or
9 will be paid to employees who are engaged in construction
10 activities associated with the renewable energy resources,
11 and the Agency shall not procure any renewable resources
12 from any entity not providing such a certification. Every
13 contract for the procurement of renewable energy resources
14 pursuant to this Section shall provide that failure to
15 comply with the terms of such certification shall
16 constitute an event of default, subject to termination of
17 the contract.

18 (d) Clean coal portfolio standard.

19 (1) The procurement plans shall include electricity
20 generated using clean coal. Each utility shall enter into
21 one or more sourcing agreements with the initial clean
22 coal facility, as provided in paragraph (3) of this
23 subsection (d), covering electricity generated by the
24 initial clean coal facility representing at least 5% of
25 each utility's total supply to serve the load of eligible
26 retail customers in 2015 and each year thereafter, as

1 described in paragraph (3) of this subsection (d), subject
2 to the limits specified in paragraph (2) of this
3 subsection (d). It is the goal of the State that by January
4 1, 2025, 25% of the electricity used in the State shall be
5 generated by cost-effective clean coal facilities. For
6 purposes of this subsection (d), "cost-effective" means
7 that the expenditures pursuant to such sourcing agreements
8 do not cause the limit stated in paragraph (2) of this
9 subsection (d) to be exceeded and do not exceed cost-based
10 benchmarks, which shall be developed to assess all
11 expenditures pursuant to such sourcing agreements covering
12 electricity generated by clean coal facilities, other than
13 the initial clean coal facility, by the procurement
14 administrator, in consultation with the Commission staff,
15 Agency staff, and the procurement monitor and shall be
16 subject to Commission review and approval.

17 A utility party to a sourcing agreement shall
18 immediately retire any emission credits that it receives
19 in connection with the electricity covered by such
20 agreement.

21 Utilities shall maintain adequate records documenting
22 the purchases under the sourcing agreement to comply with
23 this subsection (d) and shall file an accounting with the
24 load forecast that must be filed with the Agency by July 15
25 of each year, in accordance with subsection (d) of Section
26 16-111.5 of the Public Utilities Act.

1 A utility shall be deemed to have complied with the
2 clean coal portfolio standard specified in this subsection
3 (d) if the utility enters into a sourcing agreement as
4 required by this subsection (d).

5 (2) For purposes of this subsection (d), the required
6 execution of sourcing agreements with the initial clean
7 coal facility for a particular year shall be measured as a
8 percentage of the actual amount of electricity
9 (megawatt-hours) supplied by the electric utility to
10 eligible retail customers in the planning year ending
11 immediately prior to the agreement's execution. For
12 purposes of this subsection (d), the amount paid per
13 kilowatthour means the total amount paid for electric
14 service expressed on a per kilowatthour basis. For
15 purposes of this subsection (d), the total amount paid for
16 electric service includes without limitation amounts paid
17 for supply, transmission, distribution, surcharges and
18 add-on taxes.

19 Notwithstanding the requirements of this subsection
20 (d), the total amount paid under sourcing agreements with
21 clean coal facilities pursuant to the procurement plan for
22 any given year shall be reduced by an amount necessary to
23 limit the annual estimated average net increase due to the
24 costs of these resources included in the amounts paid by
25 eligible retail customers in connection with electric
26 service to:

1 (A) in 2010, no more than 0.5% of the amount paid
2 per kilowatthour by those customers during the year
3 ending May 31, 2009;

4 (B) in 2011, the greater of an additional 0.5% of
5 the amount paid per kilowatthour by those customers
6 during the year ending May 31, 2010 or 1% of the amount
7 paid per kilowatthour by those customers during the
8 year ending May 31, 2009;

9 (C) in 2012, the greater of an additional 0.5% of
10 the amount paid per kilowatthour by those customers
11 during the year ending May 31, 2011 or 1.5% of the
12 amount paid per kilowatthour by those customers during
13 the year ending May 31, 2009;

14 (D) in 2013, the greater of an additional 0.5% of
15 the amount paid per kilowatthour by those customers
16 during the year ending May 31, 2012 or 2% of the amount
17 paid per kilowatthour by those customers during the
18 year ending May 31, 2009; and

19 (E) thereafter, the total amount paid under
20 sourcing agreements with clean coal facilities
21 pursuant to the procurement plan for any single year
22 shall be reduced by an amount necessary to limit the
23 estimated average net increase due to the cost of
24 these resources included in the amounts paid by
25 eligible retail customers in connection with electric
26 service to no more than the greater of (i) 2.015% of

1 the amount paid per kilowatthour by those customers
2 during the year ending May 31, 2009 or (ii) the
3 incremental amount per kilowatthour paid for these
4 resources in 2013. These requirements may be altered
5 only as provided by statute.

6 No later than June 30, 2015, the Commission shall
7 review the limitation on the total amount paid under
8 sourcing agreements, if any, with clean coal facilities
9 pursuant to this subsection (d) and report to the General
10 Assembly its findings as to whether that limitation unduly
11 constrains the amount of electricity generated by
12 cost-effective clean coal facilities that is covered by
13 sourcing agreements.

14 (3) Initial clean coal facility. In order to promote
15 development of clean coal facilities in Illinois, each
16 electric utility subject to this Section shall execute a
17 sourcing agreement to source electricity from a proposed
18 clean coal facility in Illinois (the "initial clean coal
19 facility") that will have a nameplate capacity of at least
20 500 MW when commercial operation commences, that has a
21 final Clean Air Act permit on June 1, 2009 (the effective
22 date of Public Act 95-1027), and that will meet the
23 definition of clean coal facility in Section 1-10 of this
24 Act when commercial operation commences. The sourcing
25 agreements with this initial clean coal facility shall be
26 subject to both approval of the initial clean coal

1 facility by the General Assembly and satisfaction of the
2 requirements of paragraph (4) of this subsection (d) and
3 shall be executed within 90 days after any such approval
4 by the General Assembly. The Agency and the Commission
5 shall have authority to inspect all books and records
6 associated with the initial clean coal facility during the
7 term of such a sourcing agreement. A utility's sourcing
8 agreement for electricity produced by the initial clean
9 coal facility shall include:

10 (A) a formula contractual price (the "contract
11 price") approved pursuant to paragraph (4) of this
12 subsection (d), which shall:

13 (i) be determined using a cost of service
14 methodology employing either a level or deferred
15 capital recovery component, based on a capital
16 structure consisting of 45% equity and 55% debt,
17 and a return on equity as may be approved by the
18 Federal Energy Regulatory Commission, which in any
19 case may not exceed the lower of 11.5% or the rate
20 of return approved by the General Assembly
21 pursuant to paragraph (4) of this subsection (d);
22 and

23 (ii) provide that all miscellaneous net
24 revenue, including but not limited to net revenue
25 from the sale of emission allowances, if any,
26 substitute natural gas, if any, grants or other

1 support provided by the State of Illinois or the
2 United States Government, firm transmission
3 rights, if any, by-products produced by the
4 facility, energy or capacity derived from the
5 facility and not covered by a sourcing agreement
6 pursuant to paragraph (3) of this subsection (d)
7 or item (5) of subsection (d) of Section 16-115 of
8 the Public Utilities Act, whether generated from
9 the synthesis gas derived from coal, from SNG, or
10 from natural gas, shall be credited against the
11 revenue requirement for this initial clean coal
12 facility;

13 (B) power purchase provisions, which shall:

14 (i) provide that the utility party to such
15 sourcing agreement shall pay the contract price
16 for electricity delivered under such sourcing
17 agreement;

18 (ii) require delivery of electricity to the
19 regional transmission organization market of the
20 utility that is party to such sourcing agreement;

21 (iii) require the utility party to such
22 sourcing agreement to buy from the initial clean
23 coal facility in each hour an amount of energy
24 equal to all clean coal energy made available from
25 the initial clean coal facility during such hour
26 times a fraction, the numerator of which is such

1 utility's retail market sales of electricity
2 (expressed in kilowatthours sold) in the State
3 during the prior calendar month and the
4 denominator of which is the total retail market
5 sales of electricity (expressed in kilowatthours
6 sold) in the State by utilities during such prior
7 month and the sales of electricity (expressed in
8 kilowatthours sold) in the State by alternative
9 retail electric suppliers during such prior month
10 that are subject to the requirements of this
11 subsection (d) and paragraph (5) of subsection (d)
12 of Section 16-115 of the Public Utilities Act,
13 provided that the amount purchased by the utility
14 in any year will be limited by paragraph (2) of
15 this subsection (d); and

16 (iv) be considered pre-existing contracts in
17 such utility's procurement plans for eligible
18 retail customers;

19 (C) contract for differences provisions, which
20 shall:

21 (i) require the utility party to such sourcing
22 agreement to contract with the initial clean coal
23 facility in each hour with respect to an amount of
24 energy equal to all clean coal energy made
25 available from the initial clean coal facility
26 during such hour times a fraction, the numerator

1 of which is such utility's retail market sales of
2 electricity (expressed in kilowatthours sold) in
3 the utility's service territory in the State
4 during the prior calendar month and the
5 denominator of which is the total retail market
6 sales of electricity (expressed in kilowatthours
7 sold) in the State by utilities during such prior
8 month and the sales of electricity (expressed in
9 kilowatthours sold) in the State by alternative
10 retail electric suppliers during such prior month
11 that are subject to the requirements of this
12 subsection (d) and paragraph (5) of subsection (d)
13 of Section 16-115 of the Public Utilities Act,
14 provided that the amount paid by the utility in
15 any year will be limited by paragraph (2) of this
16 subsection (d);

17 (ii) provide that the utility's payment
18 obligation in respect of the quantity of
19 electricity determined pursuant to the preceding
20 clause (i) shall be limited to an amount equal to
21 (1) the difference between the contract price
22 determined pursuant to subparagraph (A) of
23 paragraph (3) of this subsection (d) and the
24 day-ahead price for electricity delivered to the
25 regional transmission organization market of the
26 utility that is party to such sourcing agreement

1 (or any successor delivery point at which such
2 utility's supply obligations are financially
3 settled on an hourly basis) (the "reference
4 price") on the day preceding the day on which the
5 electricity is delivered to the initial clean coal
6 facility busbar, multiplied by (2) the quantity of
7 electricity determined pursuant to the preceding
8 clause (i); and

9 (iii) not require the utility to take physical
10 delivery of the electricity produced by the
11 facility;

12 (D) general provisions, which shall:

13 (i) specify a term of no more than 30 years,
14 commencing on the commercial operation date of the
15 facility;

16 (ii) provide that utilities shall maintain
17 adequate records documenting purchases under the
18 sourcing agreements entered into to comply with
19 this subsection (d) and shall file an accounting
20 with the load forecast that must be filed with the
21 Agency by July 15 of each year, in accordance with
22 subsection (d) of Section 16-111.5 of the Public
23 Utilities Act;

24 (iii) provide that all costs associated with
25 the initial clean coal facility will be
26 periodically reported to the Federal Energy

1 Regulatory Commission and to purchasers in
2 accordance with applicable laws governing
3 cost-based wholesale power contracts;

4 (iv) permit the Illinois Power Agency to
5 assume ownership of the initial clean coal
6 facility, without monetary consideration and
7 otherwise on reasonable terms acceptable to the
8 Agency, if the Agency so requests no less than 3
9 years prior to the end of the stated contract
10 term;

11 (v) require the owner of the initial clean
12 coal facility to provide documentation to the
13 Commission each year, starting in the facility's
14 first year of commercial operation, accurately
15 reporting the quantity of carbon emissions from
16 the facility that have been captured and
17 sequestered and report any quantities of carbon
18 released from the site or sites at which carbon
19 emissions were sequestered in prior years, based
20 on continuous monitoring of such sites. If, in any
21 year after the first year of commercial operation,
22 the owner of the facility fails to demonstrate
23 that the initial clean coal facility captured and
24 sequestered at least 50% of the total carbon
25 emissions that the facility would otherwise emit
26 or that sequestration of emissions from prior

1 years has failed, resulting in the release of
2 carbon dioxide into the atmosphere, the owner of
3 the facility must offset excess emissions. Any
4 such carbon offsets must be permanent, additional,
5 verifiable, real, located within the State of
6 Illinois, and legally and practicably enforceable.
7 The cost of such offsets for the facility that are
8 not recoverable shall not exceed \$15 million in
9 any given year. No costs of any such purchases of
10 carbon offsets may be recovered from a utility or
11 its customers. All carbon offsets purchased for
12 this purpose and any carbon emission credits
13 associated with sequestration of carbon from the
14 facility must be permanently retired. The initial
15 clean coal facility shall not forfeit its
16 designation as a clean coal facility if the
17 facility fails to fully comply with the applicable
18 carbon sequestration requirements in any given
19 year, provided the requisite offsets are
20 purchased. However, the Attorney General, on
21 behalf of the People of the State of Illinois, may
22 specifically enforce the facility's sequestration
23 requirement and the other terms of this contract
24 provision. Compliance with the sequestration
25 requirements and offset purchase requirements
26 specified in paragraph (3) of this subsection (d)

1 shall be reviewed annually by an independent
2 expert retained by the owner of the initial clean
3 coal facility, with the advance written approval
4 of the Attorney General. The Commission may, in
5 the course of the review specified in item (vii),
6 reduce the allowable return on equity for the
7 facility if the facility willfully fails to comply
8 with the carbon capture and sequestration
9 requirements set forth in this item (v);

10 (vi) include limits on, and accordingly
11 provide for modification of, the amount the
12 utility is required to source under the sourcing
13 agreement consistent with paragraph (2) of this
14 subsection (d);

15 (vii) require Commission review: (1) to
16 determine the justness, reasonableness, and
17 prudence of the inputs to the formula referenced
18 in subparagraphs (A)(i) through (A)(iii) of
19 paragraph (3) of this subsection (d), prior to an
20 adjustment in those inputs including, without
21 limitation, the capital structure and return on
22 equity, fuel costs, and other operations and
23 maintenance costs and (2) to approve the costs to
24 be passed through to customers under the sourcing
25 agreement by which the utility satisfies its
26 statutory obligations. Commission review shall

1 occur no less than every 3 years, regardless of
2 whether any adjustments have been proposed, and
3 shall be completed within 9 months;

4 (viii) limit the utility's obligation to such
5 amount as the utility is allowed to recover
6 through tariffs filed with the Commission,
7 provided that neither the clean coal facility nor
8 the utility waives any right to assert federal
9 pre-emption or any other argument in response to a
10 purported disallowance of recovery costs;

11 (ix) limit the utility's or alternative retail
12 electric supplier's obligation to incur any
13 liability until such time as the facility is in
14 commercial operation and generating power and
15 energy and such power and energy is being
16 delivered to the facility busbar;

17 (x) provide that the owner or owners of the
18 initial clean coal facility, which is the
19 counterparty to such sourcing agreement, shall
20 have the right from time to time to elect whether
21 the obligations of the utility party thereto shall
22 be governed by the power purchase provisions or
23 the contract for differences provisions;

24 (xi) append documentation showing that the
25 formula rate and contract, insofar as they relate
26 to the power purchase provisions, have been

1 approved by the Federal Energy Regulatory
2 Commission pursuant to Section 205 of the Federal
3 Power Act;

4 (xii) provide that any changes to the terms of
5 the contract, insofar as such changes relate to
6 the power purchase provisions, are subject to
7 review under the public interest standard applied
8 by the Federal Energy Regulatory Commission
9 pursuant to Sections 205 and 206 of the Federal
10 Power Act; and

11 (xiii) conform with customary lender
12 requirements in power purchase agreements used as
13 the basis for financing non-utility generators.

14 (4) Effective date of sourcing agreements with the
15 initial clean coal facility. Any proposed sourcing
16 agreement with the initial clean coal facility shall not
17 become effective unless the following reports are prepared
18 and submitted and authorizations and approvals obtained:

19 (i) Facility cost report. The owner of the initial
20 clean coal facility shall submit to the Commission,
21 the Agency, and the General Assembly a front-end
22 engineering and design study, a facility cost report,
23 method of financing (including but not limited to
24 structure and associated costs), and an operating and
25 maintenance cost quote for the facility (collectively
26 "facility cost report"), which shall be prepared in

1 accordance with the requirements of this paragraph (4)
2 of subsection (d) of this Section, and shall provide
3 the Commission and the Agency access to the work
4 papers, relied upon documents, and any other backup
5 documentation related to the facility cost report.

6 (ii) Commission report. Within 6 months following
7 receipt of the facility cost report, the Commission,
8 in consultation with the Agency, shall submit a report
9 to the General Assembly setting forth its analysis of
10 the facility cost report. Such report shall include,
11 but not be limited to, a comparison of the costs
12 associated with electricity generated by the initial
13 clean coal facility to the costs associated with
14 electricity generated by other types of generation
15 facilities, an analysis of the rate impacts on
16 residential and small business customers over the life
17 of the sourcing agreements, and an analysis of the
18 likelihood that the initial clean coal facility will
19 commence commercial operation by and be delivering
20 power to the facility's busbar by 2016. To assist in
21 the preparation of its report, the Commission, in
22 consultation with the Agency, may hire one or more
23 experts or consultants, the costs of which shall be
24 paid for by the owner of the initial clean coal
25 facility. The Commission and Agency may begin the
26 process of selecting such experts or consultants prior

1 to receipt of the facility cost report.

2 (iii) General Assembly approval. The proposed
3 sourcing agreements shall not take effect unless,
4 based on the facility cost report and the Commission's
5 report, the General Assembly enacts authorizing
6 legislation approving (A) the projected price, stated
7 in cents per kilowatthour, to be charged for
8 electricity generated by the initial clean coal
9 facility, (B) the projected impact on residential and
10 small business customers' bills over the life of the
11 sourcing agreements, and (C) the maximum allowable
12 return on equity for the project; and

13 (iv) Commission review. If the General Assembly
14 enacts authorizing legislation pursuant to
15 subparagraph (iii) approving a sourcing agreement, the
16 Commission shall, within 90 days of such enactment,
17 complete a review of such sourcing agreement. During
18 such time period, the Commission shall implement any
19 directive of the General Assembly, resolve any
20 disputes between the parties to the sourcing agreement
21 concerning the terms of such agreement, approve the
22 form of such agreement, and issue an order finding
23 that the sourcing agreement is prudent and reasonable.
24 The facility cost report shall be prepared as follows:

25 (A) The facility cost report shall be prepared by
26 duly licensed engineering and construction firms

1 detailing the estimated capital costs payable to one
2 or more contractors or suppliers for the engineering,
3 procurement and construction of the components
4 comprising the initial clean coal facility and the
5 estimated costs of operation and maintenance of the
6 facility. The facility cost report shall include:

7 (i) an estimate of the capital cost of the
8 core plant based on one or more front end
9 engineering and design studies for the
10 gasification island and related facilities. The
11 core plant shall include all civil, structural,
12 mechanical, electrical, control, and safety
13 systems.

14 (ii) an estimate of the capital cost of the
15 balance of the plant, including any capital costs
16 associated with sequestration of carbon dioxide
17 emissions and all interconnects and interfaces
18 required to operate the facility, such as
19 transmission of electricity, construction or
20 backfeed power supply, pipelines to transport
21 substitute natural gas or carbon dioxide, potable
22 water supply, natural gas supply, water supply,
23 water discharge, landfill, access roads, and coal
24 delivery.

25 The quoted construction costs shall be expressed
26 in nominal dollars as of the date that the quote is

1 prepared and shall include capitalized financing costs
2 during construction, taxes, insurance, and other
3 owner's costs, and an assumed escalation in materials
4 and labor beyond the date as of which the construction
5 cost quote is expressed.

6 (B) The front end engineering and design study for
7 the gasification island and the cost study for the
8 balance of plant shall include sufficient design work
9 to permit quantification of major categories of
10 materials, commodities and labor hours, and receipt of
11 quotes from vendors of major equipment required to
12 construct and operate the clean coal facility.

13 (C) The facility cost report shall also include an
14 operating and maintenance cost quote that will provide
15 the estimated cost of delivered fuel, personnel,
16 maintenance contracts, chemicals, catalysts,
17 consumables, spares, and other fixed and variable
18 operations and maintenance costs. The delivered fuel
19 cost estimate will be provided by a recognized third
20 party expert or experts in the fuel and transportation
21 industries. The balance of the operating and
22 maintenance cost quote, excluding delivered fuel
23 costs, will be developed based on the inputs provided
24 by duly licensed engineering and construction firms
25 performing the construction cost quote, potential
26 vendors under long-term service agreements and plant

1 operating agreements, or recognized third party plant
2 operator or operators.

3 The operating and maintenance cost quote
4 (including the cost of the front end engineering and
5 design study) shall be expressed in nominal dollars as
6 of the date that the quote is prepared and shall
7 include taxes, insurance, and other owner's costs, and
8 an assumed escalation in materials and labor beyond
9 the date as of which the operating and maintenance
10 cost quote is expressed.

11 (D) The facility cost report shall also include an
12 analysis of the initial clean coal facility's ability
13 to deliver power and energy into the applicable
14 regional transmission organization markets and an
15 analysis of the expected capacity factor for the
16 initial clean coal facility.

17 (E) Amounts paid to third parties unrelated to the
18 owner or owners of the initial clean coal facility to
19 prepare the core plant construction cost quote,
20 including the front end engineering and design study,
21 and the operating and maintenance cost quote will be
22 reimbursed through Coal Development Bonds.

23 (5) Re-powering and retrofitting coal-fired power
24 plants previously owned by Illinois utilities to qualify
25 as clean coal facilities. During the 2009 procurement
26 planning process and thereafter, the Agency and the

1 Commission shall consider sourcing agreements covering
2 electricity generated by power plants that were previously
3 owned by Illinois utilities and that have been or will be
4 converted into clean coal facilities, as defined by
5 Section 1-10 of this Act. Pursuant to such procurement
6 planning process, the owners of such facilities may
7 propose to the Agency sourcing agreements with utilities
8 and alternative retail electric suppliers required to
9 comply with subsection (d) of this Section and item (5) of
10 subsection (d) of Section 16-115 of the Public Utilities
11 Act, covering electricity generated by such facilities. In
12 the case of sourcing agreements that are power purchase
13 agreements, the contract price for electricity sales shall
14 be established on a cost of service basis. In the case of
15 sourcing agreements that are contracts for differences,
16 the contract price from which the reference price is
17 subtracted shall be established on a cost of service
18 basis. The Agency and the Commission may approve any such
19 utility sourcing agreements that do not exceed cost-based
20 benchmarks developed by the procurement administrator, in
21 consultation with the Commission staff, Agency staff and
22 the procurement monitor, subject to Commission review and
23 approval. The Commission shall have authority to inspect
24 all books and records associated with these clean coal
25 facilities during the term of any such contract.

26 (6) Costs incurred under this subsection (d) or

1 pursuant to a contract entered into under this subsection
2 (d) shall be deemed prudently incurred and reasonable in
3 amount and the electric utility shall be entitled to full
4 cost recovery pursuant to the tariffs filed with the
5 Commission.

6 (d-5) Zero emission standard.

7 (1) Beginning with the delivery year commencing on
8 June 1, 2017, the Agency shall, for electric utilities
9 that serve at least 100,000 retail customers in this
10 State, procure contracts with zero emission facilities
11 that are reasonably capable of generating cost-effective
12 zero emission credits in an amount approximately equal to
13 16% of the actual amount of electricity delivered by each
14 electric utility to retail customers in the State during
15 calendar year 2014. For an electric utility serving fewer
16 than 100,000 retail customers in this State that
17 requested, under Section 16-111.5 of the Public Utilities
18 Act, that the Agency procure power and energy for all or a
19 portion of the utility's Illinois load for the delivery
20 year commencing June 1, 2016, the Agency shall procure
21 contracts with zero emission facilities that are
22 reasonably capable of generating cost-effective zero
23 emission credits in an amount approximately equal to 16%
24 of the portion of power and energy to be procured by the
25 Agency for the utility. The duration of the contracts
26 procured under this subsection (d-5) shall be for a term

1 of 10 years ending May 31, 2027. The quantity of zero
2 emission credits to be procured under the contracts shall
3 be all of the zero emission credits generated by the zero
4 emission facility in each delivery year; however, if the
5 zero emission facility is owned by more than one entity,
6 then the quantity of zero emission credits to be procured
7 under the contracts shall be the amount of zero emission
8 credits that are generated from the portion of the zero
9 emission facility that is owned by the winning supplier.

10 The 16% value identified in this paragraph (1) is the
11 average of the percentage targets in subparagraph (B) of
12 paragraph (1) of subsection (c) of this Section for the 5
13 delivery years beginning June 1, 2017.

14 The procurement process shall be subject to the
15 following provisions:

16 (A) Those zero emission facilities that intend to
17 participate in the procurement shall submit to the
18 Agency the following eligibility information for each
19 zero emission facility on or before the date
20 established by the Agency:

21 (i) the in-service date and remaining useful
22 life of the zero emission facility;

23 (ii) the amount of power generated annually
24 for each of the years 2005 through 2015, and the
25 projected zero emission credits to be generated
26 over the remaining useful life of the zero

1 emission facility, which shall be used to
2 determine the capability of each facility;

3 (iii) the annual zero emission facility cost
4 projections, expressed on a per megawatthour
5 basis, over the next 6 delivery years, which shall
6 include the following: operation and maintenance
7 expenses; fully allocated overhead costs, which
8 shall be allocated using the methodology developed
9 by the Institute for Nuclear Power Operations;
10 fuel expenditures; non-fuel capital expenditures;
11 spent fuel expenditures; a return on working
12 capital; the cost of operational and market risks
13 that could be avoided by ceasing operation; and
14 any other costs necessary for continued
15 operations, provided that "necessary" means, for
16 purposes of this item (iii), that the costs could
17 reasonably be avoided only by ceasing operations
18 of the zero emission facility; and

19 (iv) a commitment to continue operating, for
20 the duration of the contract or contracts executed
21 under the procurement held under this subsection
22 (d-5), the zero emission facility that produces
23 the zero emission credits to be procured in the
24 procurement.

25 The information described in item (iii) of this
26 subparagraph (A) may be submitted on a confidential

1 basis and shall be treated and maintained by the
2 Agency, the procurement administrator, and the
3 Commission as confidential and proprietary and exempt
4 from disclosure under subparagraphs (a) and (g) of
5 paragraph (1) of Section 7 of the Freedom of
6 Information Act. The Office of Attorney General shall
7 have access to, and maintain the confidentiality of,
8 such information pursuant to Section 6.5 of the
9 Attorney General Act.

10 (B) The price for each zero emission credit
11 procured under this subsection (d-5) for each delivery
12 year shall be in an amount that equals the Social Cost
13 of Carbon, expressed on a price per megawatthour
14 basis. However, to ensure that the procurement remains
15 affordable to retail customers in this State if
16 electricity prices increase, the price in an
17 applicable delivery year shall be reduced below the
18 Social Cost of Carbon by the amount ("Price
19 Adjustment") by which the market price index for the
20 applicable delivery year exceeds the baseline market
21 price index for the consecutive 12-month period ending
22 May 31, 2016. If the Price Adjustment is greater than
23 or equal to the Social Cost of Carbon in an applicable
24 delivery year, then no payments shall be due in that
25 delivery year. The components of this calculation are
26 defined as follows:

1 (i) Social Cost of Carbon: The Social Cost of
2 Carbon is \$16.50 per megawatthour, which is based
3 on the U.S. Interagency Working Group on Social
4 Cost of Carbon's price in the August 2016
5 Technical Update using a 3% discount rate,
6 adjusted for inflation for each year of the
7 program. Beginning with the delivery year
8 commencing June 1, 2023, the price per
9 megawatthour shall increase by \$1 per
10 megawatthour, and continue to increase by an
11 additional \$1 per megawatthour each delivery year
12 thereafter.

13 (ii) Baseline market price index: The baseline
14 market price index for the consecutive 12-month
15 period ending May 31, 2016 is \$31.40 per
16 megawatthour, which is based on the sum of (aa)
17 the average day-ahead energy price across all
18 hours of such 12-month period at the PJM
19 Interconnection LLC Northern Illinois Hub, (bb)
20 50% multiplied by the Base Residual Auction, or
21 its successor, capacity price for the rest of the
22 RTO zone group determined by PJM Interconnection
23 LLC, divided by 24 hours per day, and (cc) 50%
24 multiplied by the Planning Resource Auction, or
25 its successor, capacity price for Zone 4
26 determined by the Midcontinent Independent System

1 Operator, Inc., divided by 24 hours per day.

2 (iii) Market price index: The market price
3 index for a delivery year shall be the sum of
4 projected energy prices and projected capacity
5 prices determined as follows:

6 (aa) Projected energy prices: the
7 projected energy prices for the applicable
8 delivery year shall be calculated once for the
9 year using the forward market price for the
10 PJM Interconnection, LLC Northern Illinois
11 Hub. The forward market price shall be
12 calculated as follows: the energy forward
13 prices for each month of the applicable
14 delivery year averaged for each trade date
15 during the calendar year immediately preceding
16 that delivery year to produce a single energy
17 forward price for the delivery year. The
18 forward market price calculation shall use
19 data published by the Intercontinental
20 Exchange, or its successor.

21 (bb) Projected capacity prices:

22 (I) For the delivery years commencing
23 June 1, 2017, June 1, 2018, and June 1,
24 2019, the projected capacity price shall
25 be equal to the sum of (1) 50% multiplied
26 by the Base Residual Auction, or its

1 successor, price for the rest of the RTO
2 zone group as determined by PJM
3 Interconnection LLC, divided by 24 hours
4 per day and, (2) 50% multiplied by the
5 resource auction price determined in the
6 resource auction administered by the
7 Midcontinent Independent System Operator,
8 Inc., in which the largest percentage of
9 load cleared for Local Resource Zone 4,
10 divided by 24 hours per day, and where
11 such price is determined by the
12 Midcontinent Independent System Operator,
13 Inc.

14 (II) For the delivery year commencing
15 June 1, 2020, and each year thereafter,
16 the projected capacity price shall be
17 equal to the sum of (1) 50% multiplied by
18 the Base Residual Auction, or its
19 successor, price for the ComEd zone as
20 determined by PJM Interconnection LLC,
21 divided by 24 hours per day, and (2) 50%
22 multiplied by the resource auction price
23 determined in the resource auction
24 administered by the Midcontinent
25 Independent System Operator, Inc., in
26 which the largest percentage of load

1 cleared for Local Resource Zone 4, divided
2 by 24 hours per day, and where such price
3 is determined by the Midcontinent
4 Independent System Operator, Inc.

5 For purposes of this subsection (d-5):

6 "Rest of the RTO" and "ComEd Zone" shall have
7 the meaning ascribed to them by PJM
8 Interconnection, LLC.

9 "RTO" means regional transmission
10 organization.

11 (C) No later than 45 days after June 1, 2017 (the
12 effective date of Public Act 99-906), the Agency shall
13 publish its proposed zero emission standard
14 procurement plan. The plan shall be consistent with
15 the provisions of this paragraph (1) and shall provide
16 that winning bids shall be selected based on public
17 interest criteria that include, but are not limited
18 to, minimizing carbon dioxide emissions that result
19 from electricity consumed in Illinois and minimizing
20 sulfur dioxide, nitrogen oxide, and particulate matter
21 emissions that adversely affect the citizens of this
22 State. In particular, the selection of winning bids
23 shall take into account the incremental environmental
24 benefits resulting from the procurement, such as any
25 existing environmental benefits that are preserved by
26 the procurements held under Public Act 99-906 and

1 would cease to exist if the procurements were not
2 held, including the preservation of zero emission
3 facilities. The plan shall also describe in detail how
4 each public interest factor shall be considered and
5 weighted in the bid selection process to ensure that
6 the public interest criteria are applied to the
7 procurement and given full effect.

8 For purposes of developing the plan, the Agency
9 shall consider any reports issued by a State agency,
10 board, or commission under House Resolution 1146 of
11 the 98th General Assembly and paragraph (4) of
12 subsection (d) of this Section, as well as publicly
13 available analyses and studies performed by or for
14 regional transmission organizations that serve the
15 State and their independent market monitors.

16 Upon publishing of the zero emission standard
17 procurement plan, copies of the plan shall be posted
18 and made publicly available on the Agency's website.
19 All interested parties shall have 10 days following
20 the date of posting to provide comment to the Agency on
21 the plan. All comments shall be posted to the Agency's
22 website. Following the end of the comment period, but
23 no more than 60 days later than June 1, 2017 (the
24 effective date of Public Act 99-906), the Agency shall
25 revise the plan as necessary based on the comments
26 received and file its zero emission standard

1 procurement plan with the Commission.

2 If the Commission determines that the plan will
3 result in the procurement of cost-effective zero
4 emission credits, then the Commission shall, after
5 notice and hearing, but no later than 45 days after the
6 Agency filed the plan, approve the plan or approve
7 with modification. For purposes of this subsection
8 (d-5), "cost effective" means the projected costs of
9 procuring zero emission credits from zero emission
10 facilities do not cause the limit stated in paragraph
11 (2) of this subsection to be exceeded.

12 (C-5) As part of the Commission's review and
13 acceptance or rejection of the procurement results,
14 the Commission shall, in its public notice of
15 successful bidders:

16 (i) identify how the winning bids satisfy the
17 public interest criteria described in subparagraph
18 (C) of this paragraph (1) of minimizing carbon
19 dioxide emissions that result from electricity
20 consumed in Illinois and minimizing sulfur
21 dioxide, nitrogen oxide, and particulate matter
22 emissions that adversely affect the citizens of
23 this State;

24 (ii) specifically address how the selection of
25 winning bids takes into account the incremental
26 environmental benefits resulting from the

1 procurement, including any existing environmental
2 benefits that are preserved by the procurements
3 held under Public Act 99-906 and would have ceased
4 to exist if the procurements had not been held,
5 such as the preservation of zero emission
6 facilities;

7 (iii) quantify the environmental benefit of
8 preserving the resources identified in item (ii)
9 of this subparagraph (C-5), including the
10 following:

11 (aa) the value of avoided greenhouse gas
12 emissions measured as the product of the zero
13 emission facilities' output over the contract
14 term multiplied by the U.S. Environmental
15 Protection Agency eGrid subregion carbon
16 dioxide emission rate and the U.S. Interagency
17 Working Group on Social Cost of Carbon's price
18 in the August 2016 Technical Update using a 3%
19 discount rate, adjusted for inflation for each
20 delivery year; and

21 (bb) the costs of replacement with other
22 zero carbon dioxide resources, including wind
23 and photovoltaic, based upon the simple
24 average of the following:

25 (I) the price, or if there is more
26 than one price, the average of the prices,

1 paid for renewable energy credits from new
2 utility-scale wind projects in the
3 procurement events specified in item (i)
4 of subparagraph (G) of paragraph (1) of
5 subsection (c) of this Section; and

6 (II) the price, or if there is more
7 than one price, the average of the prices,
8 paid for renewable energy credits from new
9 utility-scale solar projects and
10 brownfield site photovoltaic projects in
11 the procurement events specified in item
12 (ii) of subparagraph (G) of paragraph (1)
13 of subsection (c) of this Section and,
14 after January 1, 2015, renewable energy
15 credits from photovoltaic distributed
16 generation projects in procurement events
17 held under subsection (c) of this Section.

18 Each utility shall enter into binding contractual
19 arrangements with the winning suppliers.

20 The procurement described in this subsection
21 (d-5), including, but not limited to, the execution of
22 all contracts procured, shall be completed no later
23 than May 10, 2017. Based on the effective date of
24 Public Act 99-906, the Agency and Commission may, as
25 appropriate, modify the various dates and timelines
26 under this subparagraph and subparagraphs (C) and (D)

1 of this paragraph (1). The procurement and plan
2 approval processes required by this subsection (d-5)
3 shall be conducted in conjunction with the procurement
4 and plan approval processes required by subsection (c)
5 of this Section and Section 16-111.5 of the Public
6 Utilities Act, to the extent practicable.
7 Notwithstanding whether a procurement event is
8 conducted under Section 16-111.5 of the Public
9 Utilities Act, the Agency shall immediately initiate a
10 procurement process on June 1, 2017 (the effective
11 date of Public Act 99-906).

12 (D) Following the procurement event described in
13 this paragraph (1) and consistent with subparagraph
14 (B) of this paragraph (1), the Agency shall calculate
15 the payments to be made under each contract for the
16 next delivery year based on the market price index for
17 that delivery year. The Agency shall publish the
18 payment calculations no later than May 25, 2017 and
19 every May 25 thereafter.

20 (E) Notwithstanding the requirements of this
21 subsection (d-5), the contracts executed under this
22 subsection (d-5) shall provide that the zero emission
23 facility may, as applicable, suspend or terminate
24 performance under the contracts in the following
25 instances:

26 (i) A zero emission facility shall be excused

1 from its performance under the contract for any
2 cause beyond the control of the resource,
3 including, but not restricted to, acts of God,
4 flood, drought, earthquake, storm, fire,
5 lightning, epidemic, war, riot, civil disturbance
6 or disobedience, labor dispute, labor or material
7 shortage, sabotage, acts of public enemy,
8 explosions, orders, regulations or restrictions
9 imposed by governmental, military, or lawfully
10 established civilian authorities, which, in any of
11 the foregoing cases, by exercise of commercially
12 reasonable efforts the zero emission facility
13 could not reasonably have been expected to avoid,
14 and which, by the exercise of commercially
15 reasonable efforts, it has been unable to
16 overcome. In such event, the zero emission
17 facility shall be excused from performance for the
18 duration of the event, including, but not limited
19 to, delivery of zero emission credits, and no
20 payment shall be due to the zero emission facility
21 during the duration of the event.

22 (ii) A zero emission facility shall be
23 permitted to terminate the contract if legislation
24 is enacted into law by the General Assembly that
25 imposes or authorizes a new tax, special
26 assessment, or fee on the generation of

1 electricity, the ownership or leasehold of a
2 generating unit, or the privilege or occupation of
3 such generation, ownership, or leasehold of
4 generation units by a zero emission facility.
5 However, the provisions of this item (ii) do not
6 apply to any generally applicable tax, special
7 assessment or fee, or requirements imposed by
8 federal law.

9 (iii) A zero emission facility shall be
10 permitted to terminate the contract in the event
11 that the resource requires capital expenditures in
12 excess of \$40,000,000 that were neither known nor
13 reasonably foreseeable at the time it executed the
14 contract and that a prudent owner or operator of
15 such resource would not undertake.

16 (iv) A zero emission facility shall be
17 permitted to terminate the contract in the event
18 the Nuclear Regulatory Commission terminates the
19 resource's license.

20 (F) If the zero emission facility elects to
21 terminate a contract under subparagraph (E) of this
22 paragraph (1), then the Commission shall reopen the
23 docket in which the Commission approved the zero
24 emission standard procurement plan under subparagraph
25 (C) of this paragraph (1) and, after notice and
26 hearing, enter an order acknowledging the contract

1 termination election if such termination is consistent
2 with the provisions of this subsection (d-5).

3 (2) For purposes of this subsection (d-5), the amount
4 paid per kilowatthour means the total amount paid for
5 electric service expressed on a per kilowatthour basis.
6 For purposes of this subsection (d-5), the total amount
7 paid for electric service includes, without limitation,
8 amounts paid for supply, transmission, distribution,
9 surcharges, and add-on taxes.

10 Notwithstanding the requirements of this subsection
11 (d-5), the contracts executed under this subsection (d-5)
12 shall provide that the total of zero emission credits
13 procured under a procurement plan shall be subject to the
14 limitations of this paragraph (2). For each delivery year,
15 the contractual volume receiving payments in such year
16 shall be reduced for all retail customers based on the
17 amount necessary to limit the net increase that delivery
18 year to the costs of those credits included in the amounts
19 paid by eligible retail customers in connection with
20 electric service to no more than 1.65% of the amount paid
21 per kilowatthour by eligible retail customers during the
22 year ending May 31, 2009. The result of this computation
23 shall apply to and reduce the procurement for all retail
24 customers, and all those customers shall pay the same
25 single, uniform cents per kilowatthour charge under
26 subsection (k) of Section 16-108 of the Public Utilities

1 Act. To arrive at a maximum dollar amount of zero emission
2 credits to be paid for the particular delivery year, the
3 resulting per kilowatthour amount shall be applied to the
4 actual amount of kilowatthours of electricity delivered by
5 the electric utility in the delivery year immediately
6 prior to the procurement, to all retail customers in its
7 service territory. Unpaid contractual volume for any
8 delivery year shall be paid in any subsequent delivery
9 year in which such payments can be made without exceeding
10 the amount specified in this paragraph (2). The
11 calculations required by this paragraph (2) shall be made
12 only once for each procurement plan year. Once the
13 determination as to the amount of zero emission credits to
14 be paid is made based on the calculations set forth in this
15 paragraph (2), no subsequent rate impact determinations
16 shall be made and no adjustments to those contract amounts
17 shall be allowed. All costs incurred under those contracts
18 and in implementing this subsection (d-5) shall be
19 recovered by the electric utility as provided in this
20 Section.

21 No later than June 30, 2019, the Commission shall
22 review the limitation on the amount of zero emission
23 credits procured under this subsection (d-5) and report to
24 the General Assembly its findings as to whether that
25 limitation unduly constrains the procurement of
26 cost-effective zero emission credits.

1 (3) Six years after the execution of a contract under
2 this subsection (d-5), the Agency shall determine whether
3 the actual zero emission credit payments received by the
4 supplier over the 6-year period exceed the Average ZEC
5 Payment. In addition, at the end of the term of a contract
6 executed under this subsection (d-5), or at the time, if
7 any, a zero emission facility's contract is terminated
8 under subparagraph (E) of paragraph (1) of this subsection
9 (d-5), then the Agency shall determine whether the actual
10 zero emission credit payments received by the supplier
11 over the term of the contract exceed the Average ZEC
12 Payment, after taking into account any amounts previously
13 credited back to the utility under this paragraph (3). If
14 the Agency determines that the actual zero emission credit
15 payments received by the supplier over the relevant period
16 exceed the Average ZEC Payment, then the supplier shall
17 credit the difference back to the utility. The amount of
18 the credit shall be remitted to the applicable electric
19 utility no later than 120 days after the Agency's
20 determination, which the utility shall reflect as a credit
21 on its retail customer bills as soon as practicable;
22 however, the credit remitted to the utility shall not
23 exceed the total amount of payments received by the
24 facility under its contract.

25 For purposes of this Section, the Average ZEC Payment
26 shall be calculated by multiplying the quantity of zero

1 emission credits delivered under the contract times the
2 average contract price. The average contract price shall
3 be determined by subtracting the amount calculated under
4 subparagraph (B) of this paragraph (3) from the amount
5 calculated under subparagraph (A) of this paragraph (3),
6 as follows:

7 (A) The average of the Social Cost of Carbon, as
8 defined in subparagraph (B) of paragraph (1) of this
9 subsection (d-5), during the term of the contract.

10 (B) The average of the market price indices, as
11 defined in subparagraph (B) of paragraph (1) of this
12 subsection (d-5), during the term of the contract,
13 minus the baseline market price index, as defined in
14 subparagraph (B) of paragraph (1) of this subsection
15 (d-5).

16 If the subtraction yields a negative number, then the
17 Average ZEC Payment shall be zero.

18 (4) Cost-effective zero emission credits procured from
19 zero emission facilities shall satisfy the applicable
20 definitions set forth in Section 1-10 of this Act.

21 (5) The electric utility shall retire all zero
22 emission credits used to comply with the requirements of
23 this subsection (d-5).

24 (6) Electric utilities shall be entitled to recover
25 all of the costs associated with the procurement of zero
26 emission credits through an automatic adjustment clause

1 tariff in accordance with subsection (k) and (m) of
2 Section 16-108 of the Public Utilities Act, and the
3 contracts executed under this subsection (d-5) shall
4 provide that the utilities' payment obligations under such
5 contracts shall be reduced if an adjustment is required
6 under subsection (m) of Section 16-108 of the Public
7 Utilities Act.

8 (7) This subsection (d-5) shall become inoperative on
9 January 1, 2028.

10 (e) The draft procurement plans are subject to public
11 comment, as required by Section 16-111.5 of the Public
12 Utilities Act.

13 (f) The Agency shall submit the final procurement plan to
14 the Commission. The Agency shall revise a procurement plan if
15 the Commission determines that it does not meet the standards
16 set forth in Section 16-111.5 of the Public Utilities Act.

17 (g) The Agency shall assess fees to each affected utility
18 to recover the costs incurred in preparation of the annual
19 procurement plan for the utility.

20 (h) The Agency shall assess fees to each bidder to recover
21 the costs incurred in connection with a competitive
22 procurement process.

23 (i) A renewable energy credit, carbon emission credit, or
24 zero emission credit can only be used once to comply with a
25 single portfolio or other standard as set forth in subsection
26 (c), subsection (d), or subsection (d-5) of this Section,

1 respectively. A renewable energy credit, carbon emission
2 credit, or zero emission credit cannot be used to satisfy the
3 requirements of more than one standard. If more than one type
4 of credit is issued for the same megawatt hour of energy, only
5 one credit can be used to satisfy the requirements of a single
6 standard. After such use, the credit must be retired together
7 with any other credits issued for the same megawatt hour of
8 energy.

9 (Source: P.A. 100-863, eff. 8-14-18; 101-81, eff. 7-12-19;
10 101-113, eff. 1-1-20.)

11 Section 10. The Public Utilities Act is amended by
12 changing Sections 5-117, 8-103B, 16-102, 16-107.6, 16-108.5,
13 16-111.5, and 16-128A and by adding Sections 8-218, 9-244.5,
14 16-108.19 and 16-108.20 as follows:

15 (220 ILCS 5/5-117)

16 Sec. 5-117. Supplier diversity goals.

17 (a) The public policy of this State is to collaboratively
18 work with companies that serve Illinois residents to improve
19 their supplier diversity in a non-antagonistic manner.

20 (b) The Commission shall require all gas, electric, and
21 water companies with at least 100,000 customers under its
22 authority, as well as suppliers of wind energy, solar energy,
23 hydroelectricity, nuclear energy, and any other supplier of
24 energy within this State, including, but not limited to, any

1 party selling renewable energy resources procured by the
2 Illinois Power Agency pursuant to Section 16-111.5 of this Act
3 and Section 1-75 of the Illinois Power Agency Act, to submit an
4 annual report by April 15, 2015 and every April 15 thereafter,
5 in a searchable Adobe PDF format, on all procurement goals and
6 actual spending for woman-owned ~~female-owned~~, minority-owned,
7 veteran-owned, and small business enterprises in the previous
8 calendar year. These goals shall be expressed as a percentage
9 of the total work performed by the entity submitting the
10 report, and the actual spending for all woman-owned
11 ~~female-owned~~, minority-owned, veteran-owned, and small
12 business enterprises shall also be expressed as a percentage
13 of the total work performed by the entity submitting the
14 report. Nothing in this subsection (b) shall require any
15 entity that was not required to file a report pursuant to this
16 subsection (b) prior to the effective date of this amendatory
17 Act of the 102nd General Assembly to file reports for calendar
18 years prior to 2021.

19 (c) Each participating company in its annual report shall
20 include the following information:

21 (1) an explanation of the plan for the next year to
22 increase participation;

23 (2) an explanation of the plan to increase the goals;

24 (3) the areas of procurement each company shall be
25 actively seeking more participation in ~~in~~ the next year;

26 (4) an outline of the plan to alert and encourage

1 potential vendors in that area to seek business from the
2 company;

3 (5) an explanation of the challenges faced in finding
4 quality vendors and offer any suggestions for what the
5 Commission could do to be helpful to identify those
6 vendors;

7 (6) a list of the certifications the company
8 recognizes;

9 (7) the point of contact for any potential vendor who
10 wishes to do business with the company and explain the
11 process for a vendor to enroll with the company as a
12 minority-owned, women-owned, or veteran-owned company; and

13 (8) any particular success stories to encourage other
14 companies to emulate best practices.

15 (d) Each annual report shall include as much
16 State-specific data as possible. If the submitting entity does
17 not submit State-specific data, then the company shall include
18 any national data it does have and explain why it could not
19 submit State-specific data and how it intends to do so in
20 future reports, if possible.

21 (e) Each annual report shall include the rules,
22 regulations, and definitions used for the procurement goals in
23 the company's annual report.

24 (f) The Commission and all participating entities shall
25 hold an annual workshop open to the public in 2015 and every
26 year thereafter on the state of supplier diversity to

1 collaboratively seek solutions to structural impediments to
2 achieving stated goals, including testimony from each
3 participating entity as well as subject matter experts and
4 advocates. The Commission shall publish a database on its
5 website of the point of contact for each participating entity
6 for supplier diversity, along with a list of certifications
7 each company recognizes from the information submitted in each
8 annual report. The Commission shall publish each annual report
9 on its website and shall maintain each annual report for at
10 least 5 years.

11 (Source: P.A. 98-1056, eff. 8-26-14; 99-906, eff. 6-1-17;
12 revised 7-22-19.)

13 (220 ILCS 5/8-103B)

14 Sec. 8-103B. Energy efficiency and demand-response
15 measures.

16 (a) It is the policy of the State that electric utilities
17 are required to use cost-effective energy efficiency and
18 demand-response measures to reduce the total Btus of
19 electricity, natural gas, or other fuels needed to meet the
20 end use or uses for all retail customers ~~delivery load~~.

21 Requiring investment in cost-effective energy efficiency and
22 demand-response measures will reduce direct and indirect costs
23 to consumers by decreasing environmental impacts and by
24 avoiding or delaying the need for new generation,
25 transmission, and distribution infrastructure. It serves the

1 public interest to allow electric utilities to recover costs
2 for reasonably and prudently incurred expenditures for energy
3 efficiency and demand-response measures. As used in this
4 Section, "cost-effective" means that the measures satisfy the
5 total resource cost test. The low-income measures described in
6 subsection (c) of this Section shall not be required to meet
7 the total resource cost test. For purposes of this Section,
8 the terms "energy-efficiency", "demand-response", "electric
9 utility", and "total resource cost test" have the meanings set
10 forth in the Illinois Power Agency Act.

11 (a-5) This Section applies to electric utilities serving
12 more than 500,000 retail customers in the State for those
13 multi-year plans commencing after December 31, 2017.

14 (b) For purposes of this Section, electric utilities
15 subject to this Section that serve more than 3,000,000 retail
16 customers in the State shall be deemed to have achieved a
17 cumulative persisting annual savings of 6.6% from energy
18 efficiency measures and programs implemented during the period
19 beginning January 1, 2012 and ending December 31, 2017, which
20 percent is based on the deemed average weather normalized
21 sales of electric power and energy during calendar years 2014,
22 2015, and 2016 of 88,000,000 MWhs. For the purposes of this
23 subsection (b) and subsection (b-5), the 88,000,000 MWhs of
24 deemed electric power and energy sales shall be reduced by the
25 number of MWhs equal to the sum of the annual consumption of
26 customers that are exempt from subsections (a) through (j) of

1 this Section under subsection (1) of this Section, as averaged
2 across the calendar years 2014, 2015, and 2016. After 2017,
3 the deemed value of cumulative persisting annual savings from
4 energy efficiency measures and programs implemented during the
5 period beginning January 1, 2012 and ending December 31, 2017,
6 shall be reduced each year, as follows, and the applicable
7 value shall be applied to and count toward the utility's
8 achievement of the cumulative persisting annual savings goals
9 set forth in subsection (b-5):

10 (1) 5.8% deemed cumulative persisting annual savings
11 for the year ending December 31, 2018;

12 (2) 5.2% deemed cumulative persisting annual savings
13 for the year ending December 31, 2019;

14 (3) 4.5% deemed cumulative persisting annual savings
15 for the year ending December 31, 2020;

16 (4) 4.0% deemed cumulative persisting annual savings
17 for the year ending December 31, 2021;

18 (5) 3.5% deemed cumulative persisting annual savings
19 for the year ending December 31, 2022;

20 (6) 3.1% deemed cumulative persisting annual savings
21 for the year ending December 31, 2023;

22 (7) 2.8% deemed cumulative persisting annual savings
23 for the year ending December 31, 2024;

24 (8) 2.5% deemed cumulative persisting annual savings
25 for the year ending December 31, 2025;

26 (9) 2.3% deemed cumulative persisting annual savings

1 for the year ending December 31, 2026;

2 (10) 2.1% deemed cumulative persisting annual savings
3 for the year ending December 31, 2027;

4 (11) 1.8% deemed cumulative persisting annual savings
5 for the year ending December 31, 2028;

6 (12) 1.7% deemed cumulative persisting annual savings
7 for the year ending December 31, 2029; and

8 (13) 1.5% deemed cumulative persisting annual savings
9 for the year ending December 31, 2030.

10 For purposes of this Section, "cumulative persisting
11 annual savings" means the total electric energy savings in a
12 given year from measures installed in that year or in previous
13 years, but no earlier than January 1, 2012, that are still
14 operational and providing savings in that year because the
15 measures have not yet reached the end of their useful lives.

16 (b-5) Beginning in 2018, electric utilities subject to
17 this Section that serve more than 3,000,000 retail customers
18 in the State shall achieve the following cumulative persisting
19 annual savings goals, as modified by subsection (f) of this
20 Section and as compared to the deemed baseline of 88,000,000
21 MWhs of electric power and energy sales set forth in
22 subsection (b), as reduced by the number of MWhs equal to the
23 sum of the annual consumption of customers that are exempt
24 from subsections (a) through (j) of this Section under
25 subsection (l) of this Section as averaged across the calendar
26 years 2014, 2015, and 2016, through the implementation of

1 energy efficiency measures during the applicable year and in
2 prior years, but no earlier than January 1, 2012:

3 (1) 7.8% cumulative persisting annual savings for the
4 year ending December 31, 2018;

5 (2) 9.1% cumulative persisting annual savings for the
6 year ending December 31, 2019;

7 (3) 10.4% cumulative persisting annual savings for the
8 year ending December 31, 2020;

9 (4) 11.8% cumulative persisting annual savings for the
10 year ending December 31, 2021;

11 (5) 13.1% cumulative persisting annual savings for the
12 year ending December 31, 2022;

13 (6) 14.4% cumulative persisting annual savings for the
14 year ending December 31, 2023;

15 (7) 15.7% cumulative persisting annual savings for the
16 year ending December 31, 2024;

17 (8) 17% cumulative persisting annual savings for the
18 year ending December 31, 2025;

19 (9) 17.9% cumulative persisting annual savings for the
20 year ending December 31, 2026;

21 (10) 18.8% cumulative persisting annual savings for
22 the year ending December 31, 2027;

23 (11) 19.7% cumulative persisting annual savings for
24 the year ending December 31, 2028;

25 (12) 20.6% cumulative persisting annual savings for
26 the year ending December 31, 2029; and

1 (13) 21.5% cumulative persisting annual savings for
2 the year ending December 31, 2030.

3 (b-10) For purposes of this Section, electric utilities
4 subject to this Section that serve less than 3,000,000 retail
5 customers but more than 500,000 retail customers in the State
6 shall be deemed to have achieved a cumulative persisting
7 annual savings of 6.6% from energy efficiency measures and
8 programs implemented during the period beginning January 1,
9 2012 and ending December 31, 2017, which is based on the deemed
10 average weather normalized sales of electric power and energy
11 during calendar years 2014, 2015, and 2016 of 36,900,000 MWhs.
12 For the purposes of this subsection (b-10) and subsection
13 (b-15), the 36,900,000 MWhs of deemed electric power and
14 energy sales shall be reduced by the number of MWhs equal to
15 the sum of the annual consumption of customers that are exempt
16 from subsections (a) through (j) of this Section under
17 subsection (l) of this Section, as averaged across the
18 calendar years 2014, 2015, and 2016. After 2017, the deemed
19 value of cumulative persisting annual savings from energy
20 efficiency measures and programs implemented during the period
21 beginning January 1, 2012 and ending December 31, 2017, shall
22 be reduced each year, as follows, and the applicable value
23 shall be applied to and count toward the utility's achievement
24 of the cumulative persisting annual savings goals set forth in
25 subsection (b-15):

26 (1) 5.8% deemed cumulative persisting annual savings

- 1 for the year ending December 31, 2018;
- 2 (2) 5.2% deemed cumulative persisting annual savings
- 3 for the year ending December 31, 2019;
- 4 (3) 4.5% deemed cumulative persisting annual savings
- 5 for the year ending December 31, 2020;
- 6 (4) 4.0% deemed cumulative persisting annual savings
- 7 for the year ending December 31, 2021;
- 8 (5) 3.5% deemed cumulative persisting annual savings
- 9 for the year ending December 31, 2022;
- 10 (6) 3.1% deemed cumulative persisting annual savings
- 11 for the year ending December 31, 2023;
- 12 (7) 2.8% deemed cumulative persisting annual savings
- 13 for the year ending December 31, 2024;
- 14 (8) 2.5% deemed cumulative persisting annual savings
- 15 for the year ending December 31, 2025;
- 16 (9) 2.3% deemed cumulative persisting annual savings
- 17 for the year ending December 31, 2026;
- 18 (10) 2.1% deemed cumulative persisting annual savings
- 19 for the year ending December 31, 2027;
- 20 (11) 1.8% deemed cumulative persisting annual savings
- 21 for the year ending December 31, 2028;
- 22 (12) 1.7% deemed cumulative persisting annual savings
- 23 for the year ending December 31, 2029; and
- 24 (13) 1.5% deemed cumulative persisting annual savings
- 25 for the year ending December 31, 2030.
- 26 (b-15) Beginning in 2018, electric utilities subject to

1 this Section that serve less than 3,000,000 retail customers
2 but more than 500,000 retail customers in the State shall
3 achieve the following cumulative persisting annual savings
4 goals, as modified by subsection (b-20) and subsection (f) of
5 this Section and as compared to the deemed baseline as reduced
6 by the number of MWhs equal to the sum of the annual
7 consumption of customers that are exempt from subsections (a)
8 through (j) of this Section under subsection (l) of this
9 Section as averaged across the calendar years 2014, 2015, and
10 2016, through the implementation of energy efficiency measures
11 during the applicable year and in prior years, but no earlier
12 than January 1, 2012:

13 (1) 7.4% cumulative persisting annual savings for the
14 year ending December 31, 2018;

15 (2) 8.2% cumulative persisting annual savings for the
16 year ending December 31, 2019;

17 (3) 9.0% cumulative persisting annual savings for the
18 year ending December 31, 2020;

19 (4) 9.8% cumulative persisting annual savings for the
20 year ending December 31, 2021;

21 (5) 10.6% cumulative persisting annual savings for the
22 year ending December 31, 2022;

23 (6) 11.4% cumulative persisting annual savings for the
24 year ending December 31, 2023;

25 (7) 12.2% cumulative persisting annual savings for the
26 year ending December 31, 2024;

1 (8) 13% cumulative persisting annual savings for the
2 year ending December 31, 2025;

3 (9) 13.6% cumulative persisting annual savings for the
4 year ending December 31, 2026;

5 (10) 14.2% cumulative persisting annual savings for
6 the year ending December 31, 2027;

7 (11) 14.8% cumulative persisting annual savings for
8 the year ending December 31, 2028;

9 (12) 15.4% cumulative persisting annual savings for
10 the year ending December 31, 2029; and

11 (13) 16% cumulative persisting annual savings for the
12 year ending December 31, 2030.

13 The difference between the cumulative persisting annual
14 savings goal for the applicable calendar year and the
15 cumulative persisting annual savings goal for the immediately
16 preceding calendar year is 0.8% for the period of January 1,
17 2018 through December 31, 2025 and 0.6% for the period of
18 January 1, 2026 through December 31, 2030.

19 (b-20) Each electric utility subject to this Section may
20 include cost-effective voltage optimization measures in its
21 plans submitted under subsections (f) and (g) of this Section,
22 and the costs incurred by a utility to implement the measures
23 under a Commission-approved plan shall be recovered under the
24 provisions of Article IX or Section 16-108.5 of this Act. For
25 purposes of this Section, the measure life of voltage
26 optimization measures shall be 15 years. The measure life

1 period is independent of the depreciation rate of the voltage
2 optimization assets deployed.

3 Within 270 days after June 1, 2017 (the effective date of
4 Public Act 99-906), an electric utility that serves less than
5 3,000,000 retail customers but more than 500,000 retail
6 customers in the State shall file a plan with the Commission
7 that identifies the cost-effective voltage optimization
8 investment the electric utility plans to undertake through
9 December 31, 2024. The Commission, after notice and hearing,
10 shall approve or approve with modification the plan within 120
11 days after the plan's filing and, in the order approving or
12 approving with modification the plan, the Commission shall
13 adjust the applicable cumulative persisting annual savings
14 goals set forth in subsection (b-15) to reflect any amount of
15 cost-effective energy savings approved by the Commission that
16 is greater than or less than the following cumulative
17 persisting annual savings values attributable to voltage
18 optimization for the applicable year:

19 (1) 0.0% of cumulative persisting annual savings for
20 the year ending December 31, 2018;

21 (2) 0.17% of cumulative persisting annual savings for
22 the year ending December 31, 2019;

23 (3) 0.17% of cumulative persisting annual savings for
24 the year ending December 31, 2020;

25 (4) 0.33% of cumulative persisting annual savings for
26 the year ending December 31, 2021;

1 (5) 0.5% of cumulative persisting annual savings for
2 the year ending December 31, 2022;

3 (6) 0.67% of cumulative persisting annual savings for
4 the year ending December 31, 2023;

5 (7) 0.83% of cumulative persisting annual savings for
6 the year ending December 31, 2024; and

7 (8) 1.0% of cumulative persisting annual savings for
8 the year ending December 31, 2025.

9 (b-25) In the event an electric utility jointly offers an
10 energy efficiency measure or program with a gas utility under
11 plans approved under this Section and Section 8-104 of this
12 Act, the electric utility may continue offering the program,
13 including the gas energy efficiency measures, in the event the
14 gas utility discontinues funding the program. In that event,
15 the energy savings value associated with such other fuels
16 shall be converted to electric energy savings on an equivalent
17 Btu basis for the premises. However, the electric utility
18 shall prioritize programs for low-income residential customers
19 to the extent practicable. An electric utility may recover the
20 costs of offering the gas energy efficiency measures under
21 this subsection (b-25).

22 For those energy efficiency measures or programs that save
23 both electricity and other fuels but are not jointly offered
24 with a gas utility under plans approved under this Section and
25 Section 8-104 or not offered with an affiliated gas utility
26 under paragraph (6) of subsection (f) of Section 8-104 of this

1 Act, or for those energy efficiency measures that achieve
2 savings of fuels other than electricity, an ~~the~~ electric
3 utility may count savings of fuels other than electricity
4 toward the achievement of its annual savings goal, and the
5 energy savings value associated with such other fuels shall be
6 converted to electric energy savings on an equivalent Btu
7 basis at the premises.

8 In no event shall more than 10% of each year's applicable
9 annual incremental goal as defined in paragraph (7) of
10 subsection (g) of this Section be met through savings of fuels
11 other than electricity; however, savings of fuels other than
12 electricity achieved by measures that educate about,
13 incentivize, encourage, or otherwise support the use of
14 electricity to power, in whole or in part, vehicles,
15 including, but not limited to, cars, trucks, buses, trains,
16 trolleys, boats, on-road or off-road vehicles, or other
17 equipment or methods of transporting goods or people, shall
18 count towards the applicable annual incremental goal and shall
19 not be included in the 10% limit set forth in this subsection
20 (b-25). Such measures shall include, but are not limited to,
21 measures that educate about, incentivize, encourage, or
22 otherwise support the adoption of electric vehicles by retail
23 customers of all customer classes.

24 (c) Electric utilities shall be responsible for overseeing
25 the design, development, and filing of energy efficiency plans
26 with the Commission and may, as part of that implementation,

1 outsource various aspects of program development and
2 implementation. A minimum of 10%, for electric utilities that
3 serve more than 3,000,000 retail customers in the State, and a
4 minimum of 7%, for electric utilities that serve less than
5 3,000,000 retail customers but more than 500,000 retail
6 customers in the State, of the utility's entire portfolio
7 funding level for a given year shall be used to procure
8 cost-effective energy efficiency measures from units of local
9 government, municipal corporations, school districts, public
10 housing, and community college districts, provided that a
11 minimum percentage of available funds shall be used to procure
12 energy efficiency from public housing, which percentage shall
13 be equal to public housing's share of public building energy
14 consumption.

15 The utilities shall also implement energy efficiency
16 measures targeted at low-income households, which, for
17 purposes of this Section, shall be defined as households at or
18 below 80% of area median income, and expenditures to implement
19 the measures shall be no less than \$25,000,000 per year for
20 electric utilities that serve more than 3,000,000 retail
21 customers in the State and no less than \$8,350,000 per year for
22 electric utilities that serve less than 3,000,000 retail
23 customers but more than 500,000 retail customers in the State.

24 Each electric utility shall assess opportunities to
25 implement cost-effective energy efficiency measures and
26 programs through a public housing authority or authorities

1 located in its service territory. If such opportunities are
2 identified, the utility shall propose such measures and
3 programs to address the opportunities. Expenditures to address
4 such opportunities shall be credited toward the minimum
5 procurement and expenditure requirements set forth in this
6 subsection (c).

7 Implementation of energy efficiency measures and programs
8 targeted at low-income households should be contracted, when
9 it is practicable, to independent third parties that have
10 demonstrated capabilities to serve such households, with a
11 preference for not-for-profit entities and government agencies
12 that have existing relationships with or experience serving
13 low-income communities in the State.

14 Each electric utility shall develop and implement
15 reporting procedures that address and assist in determining
16 the amount of energy savings that can be applied to the
17 low-income procurement and expenditure requirements set forth
18 in this subsection (c).

19 The electric utilities shall also convene a low-income
20 energy efficiency advisory committee to assist in the design
21 and evaluation of the low-income energy efficiency programs.
22 The committee shall be comprised of the electric utilities
23 subject to the requirements of this Section, the gas utilities
24 subject to the requirements of Section 8-104 of this Act, the
25 utilities' low-income energy efficiency implementation
26 contractors, and representatives of community-based

1 organizations.

2 (d) Notwithstanding any other provision of law to the
3 contrary, a utility providing approved energy efficiency
4 measures and, if applicable, demand-response measures in the
5 State shall be permitted to recover all reasonable and
6 prudently incurred costs of those measures from all retail
7 customers, except as provided in subsection (1) of this
8 Section, as follows, provided that nothing in this subsection
9 (d) permits the double recovery of such costs from customers:

10 (1) The utility may recover its costs through an
11 automatic adjustment clause tariff filed with and approved
12 by the Commission. The tariff shall be established outside
13 the context of a general rate case. Each year the
14 Commission shall initiate a review to reconcile any
15 amounts collected with the actual costs and to determine
16 the required adjustment to the annual tariff factor to
17 match annual expenditures. To enable the financing of the
18 incremental capital expenditures, including regulatory
19 assets, for electric utilities that serve less than
20 3,000,000 retail customers but more than 500,000 retail
21 customers in the State, the utility's actual year-end
22 capital structure that includes a common equity ratio,
23 excluding goodwill, of up to and including 54% ~~50%~~ of the
24 total capital structure shall be deemed reasonable and
25 used to set rates.

26 (2) A utility may recover its costs through an energy

1 efficiency formula rate approved by the Commission under a
2 filing under subsections (f) and (g) of this Section,
3 which shall specify the cost components that form the
4 basis of the rate charged to customers with sufficient
5 specificity to operate in a standardized manner and be
6 updated annually with transparent information that
7 reflects the utility's actual costs to be recovered during
8 the applicable rate year, which is the period beginning
9 with the first billing day of January and extending
10 through the last billing day of the following December.
11 The energy efficiency formula rate shall be implemented
12 through a tariff filed with the Commission under
13 subsections (f) and (g) of this Section that is consistent
14 with the provisions of this paragraph (2) and that shall
15 be applicable to all delivery services customers. The
16 Commission shall conduct an investigation of the tariff in
17 a manner consistent with the provisions of this paragraph
18 (2), subsections (f) and (g) of this Section, and the
19 provisions of Article IX of this Act to the extent they do
20 not conflict with this paragraph (2). The energy
21 efficiency formula rate approved by the Commission shall
22 remain in effect at the discretion of the utility and
23 shall do the following:

24 (A) Provide for the recovery of the utility's
25 actual costs incurred under this Section that are
26 prudently incurred and reasonable in amount consistent

1 with Commission practice and law. The sole fact that a
2 cost differs from that incurred in a prior calendar
3 year or that an investment is different from that made
4 in a prior calendar year shall not imply the
5 imprudence or unreasonableness of that cost or
6 investment.

7 (B) Reflect the utility's actual year-end capital
8 structure for the applicable calendar year, excluding
9 goodwill, subject to a determination of prudence and
10 reasonableness consistent with Commission practice and
11 law. To enable the financing of the incremental
12 capital expenditures, including regulatory assets, for
13 electric utilities that serve less than 3,000,000
14 retail customers but more than 500,000 retail
15 customers in the State, a participating electric
16 utility's actual year-end capital structure that
17 includes a common equity ratio, excluding goodwill, of
18 up to and including 54% ~~50%~~ of the total capital
19 structure shall be deemed reasonable and used to set
20 rates.

21 (C) Include a cost of equity, which in all
22 calendar years for electric utilities that serve
23 3,000,000 or more retail customers in this State, and
24 in each calendar year commencing before January 1,
25 2021 for electric utilities that serve less than
26 3,000,000 retail customers but more than 500,000

1 retail customers in this State, shall be calculated as
2 the sum of the following:

3 (i) the average for the applicable calendar
4 year of the monthly average yields of 30-year U.S.
5 Treasury bonds published by the Board of Governors
6 of the Federal Reserve System in its weekly H.15
7 Statistical Release or successor publication; and

8 (ii) 580 basis points.

9 For electric utilities that serve less than
10 3,000,000 retail customers but more than 500,000
11 retail customers in this State, for each calendar year
12 commencing after December 31, 2020, the cost of equity
13 shall be equal to the national average cost of equity
14 as calculated under this subparagraph (C) of this
15 paragraph (2). For purposes of this subparagraph (C)
16 of this paragraph (2), the national average cost of
17 equity for an applicable calendar year shall be the
18 simple average of the cost of equity specified and
19 approved in each order of a state regulatory
20 commission, other than the Commission, issued during
21 such calendar year that is applicable to base rates
22 for retail electric service provided by an
23 investor-owned public utility company operating in the
24 United States. No order shall be excluded from the
25 national average cost of equity calculated under this
26 subparagraph (C) of this paragraph (2) on the grounds

1 that it was arrived at by stipulation or agreement or
2 is subject to rehearing or appeal. In its final order
3 in the proceeding, occurring pursuant to subsection
4 (d) of this Section during calendar year 2021, the
5 Commission shall set the cost of equity using the
6 method applicable to calendar years commencing prior
7 to January 1, 2021. In its final orders in the
8 proceedings, occurring pursuant to subsection (d) of
9 this Section in years subsequent to calendar year
10 2021, including the reconciliation of the 2021 rate
11 year, the Commission shall set the cost of equity
12 using the method applicable to calendar years
13 commencing after December 31, 2020. If, for any
14 calendar year, there are fewer than 15 applicable
15 orders of state regulatory commissions with which to
16 compute the average cost of equity under this
17 subparagraph (C) of this paragraph (2), the Commission
18 shall include in the calculation of the national
19 average the number of state regulatory orders from the
20 year or years immediately preceding such calendar year
21 necessary to reach a total of 15, beginning with the
22 most recently issued and proceeding in reverse
23 chronological order.

24 At such time as the Board of Governors of the
25 Federal Reserve System ceases to include the monthly
26 average yields of 30-year U.S. Treasury bonds in its

1 weekly H.15 Statistical Release or successor
2 publication, the monthly average yields of the U.S.
3 Treasury bonds then having the longest duration
4 published by the Board of Governors in its weekly H.15
5 Statistical Release or successor publication shall
6 instead be used for purposes of this paragraph (2).

7 (D) Permit and set forth protocols, subject to a
8 determination of prudence and reasonableness
9 consistent with Commission practice and law, for the
10 following:

11 (i) recovery of incentive compensation expense
12 that is based on the achievement of operational
13 metrics, including metrics related to budget
14 controls, outage duration and frequency, safety,
15 customer service, efficiency and productivity, and
16 environmental compliance; however, this protocol
17 shall not apply if such expense related to costs
18 incurred under this Section is recovered under
19 Article IX or Section 16-108.5 of this Act;
20 incentive compensation expense that is based on
21 net income or an affiliate's earnings per share
22 shall not be recoverable under the energy
23 efficiency formula rate;

24 (ii) recovery of pension and other
25 post-employment benefits expense, provided that
26 such costs are supported by an actuarial study;

1 however, this protocol shall not apply if such
2 expense related to costs incurred under this
3 Section is recovered under Article IX or Section
4 16-108.5 of this Act;

5 (iii) recovery of existing regulatory assets
6 over the periods previously authorized by the
7 Commission;

8 (iv) as described in subsection (e),
9 amortization of costs incurred under this Section;
10 and

11 (v) projected, weather normalized billing
12 determinants for the applicable rate year.

13 (E) Provide for an annual reconciliation, as
14 described in paragraph (3) of this subsection (d),
15 less any deferred taxes related to the reconciliation,
16 with interest at an annual rate of return equal to the
17 utility's weighted average cost of capital, including
18 a revenue conversion factor calculated to recover or
19 refund all additional income taxes that may be payable
20 or receivable as a result of that return, of the energy
21 efficiency revenue requirement reflected in rates for
22 each calendar year, beginning with the calendar year
23 in which the utility files its energy efficiency
24 formula rate tariff under this paragraph (2), with
25 what the revenue requirement would have been had the
26 actual cost information for the applicable calendar

1 year been available at the filing date.

2 The utility shall file, together with its tariff, the
3 projected costs to be incurred by the utility during the
4 rate year under the utility's multi-year plan approved
5 under subsections (f) and (g) of this Section, including,
6 but not limited to, the projected capital investment costs
7 and projected regulatory asset balances with
8 correspondingly updated depreciation and amortization
9 reserves and expense, that shall populate the energy
10 efficiency formula rate and set the initial rates under
11 the formula.

12 The Commission shall review the proposed tariff in
13 conjunction with its review of a proposed multi-year plan,
14 as specified in paragraph (5) of subsection (g) of this
15 Section. The review shall be based on the same evidentiary
16 standards, including, but not limited to, those concerning
17 the prudence and reasonableness of the costs incurred by
18 the utility, the Commission applies in a hearing to review
19 a filing for a general increase in rates under Article IX
20 of this Act. The initial rates shall take effect beginning
21 with the January monthly billing period following the
22 Commission's approval.

23 The tariff's rate design and cost allocation across
24 customer classes shall be consistent with the utility's
25 automatic adjustment clause tariff in effect on June 1,
26 2017 (the effective date of Public Act 99-906); however,

1 the Commission may revise the tariff's rate design and
2 cost allocation in subsequent proceedings under paragraph
3 (3) of this subsection (d).

4 If the energy efficiency formula rate is terminated,
5 the then current rates shall remain in effect until such
6 time as the energy efficiency costs are incorporated into
7 new rates that are set under this subsection (d) or
8 Article IX of this Act, subject to retroactive rate
9 adjustment, with interest, to reconcile rates charged with
10 actual costs.

11 (3) The provisions of this paragraph (3) shall only
12 apply to an electric utility that has elected to file an
13 energy efficiency formula rate under paragraph (2) of this
14 subsection (d). Subsequent to the Commission's issuance of
15 an order approving the utility's energy efficiency formula
16 rate structure and protocols, and initial rates under
17 paragraph (2) of this subsection (d), the utility shall
18 file, on or before June 1 of each year, with the Chief
19 Clerk of the Commission its updated cost inputs to the
20 energy efficiency formula rate for the applicable rate
21 year and the corresponding new charges, as well as the
22 information described in paragraph (9) of subsection (g)
23 of this Section. Each such filing shall conform to the
24 following requirements and include the following
25 information:

26 (A) The inputs to the energy efficiency formula

1 rate for the applicable rate year shall be based on the
2 projected costs to be incurred by the utility during
3 the rate year under the utility's multi-year plan
4 approved under subsections (f) and (g) of this
5 Section, including, but not limited to, projected
6 capital investment costs and projected regulatory
7 asset balances with correspondingly updated
8 depreciation and amortization reserves and expense.
9 The filing shall also include a reconciliation of the
10 energy efficiency revenue requirement that was in
11 effect for the prior rate year (as set by the cost
12 inputs for the prior rate year) with the actual
13 revenue requirement for the prior rate year
14 (determined using a year-end rate base) that uses
15 amounts reflected in the applicable FERC Form 1 that
16 reports the actual costs for the prior rate year. Any
17 over-collection or under-collection indicated by such
18 reconciliation shall be reflected as a credit against,
19 or recovered as an additional charge to, respectively,
20 with interest calculated at a rate equal to the
21 utility's weighted average cost of capital approved by
22 the Commission for the prior rate year, the charges
23 for the applicable rate year. Such over-collection or
24 under-collection shall be adjusted to remove any
25 deferred taxes related to the reconciliation, for
26 purposes of calculating interest at an annual rate of

1 return equal to the utility's weighted average cost of
2 capital approved by the Commission for the prior rate
3 year, including a revenue conversion factor calculated
4 to recover or refund all additional income taxes that
5 may be payable or receivable as a result of that
6 return. Each reconciliation shall be certified by the
7 participating utility in the same manner that FERC
8 Form 1 is certified. The filing shall also include the
9 charge or credit, if any, resulting from the
10 calculation required by subparagraph (E) of paragraph
11 (2) of this subsection (d).

12 Notwithstanding any other provision of law to the
13 contrary, the intent of the reconciliation is to
14 ultimately reconcile both the revenue requirement
15 reflected in rates for each calendar year, beginning
16 with the calendar year in which the utility files its
17 energy efficiency formula rate tariff under paragraph
18 (2) of this subsection (d), with what the revenue
19 requirement determined using a year-end rate base for
20 the applicable calendar year would have been had the
21 actual cost information for the applicable calendar
22 year been available at the filing date.

23 For purposes of this Section, "FERC Form 1" means
24 the Annual Report of Major Electric Utilities,
25 Licensees and Others that electric utilities are
26 required to file with the Federal Energy Regulatory

1 Commission under the Federal Power Act, Sections 3,
2 4(a), 304 and 209, modified as necessary to be
3 consistent with 83 Ill. Admin. Code Part 415 as of May
4 1, 2011. Nothing in this Section is intended to allow
5 costs that are not otherwise recoverable to be
6 recoverable by virtue of inclusion in FERC Form 1.

7 (B) The new charges shall take effect beginning on
8 the first billing day of the following January billing
9 period and remain in effect through the last billing
10 day of the next December billing period regardless of
11 whether the Commission enters upon a hearing under
12 this paragraph (3).

13 (C) The filing shall include relevant and
14 necessary data and documentation for the applicable
15 rate year. Normalization adjustments shall not be
16 required.

17 Within 45 days after the utility files its annual
18 update of cost inputs to the energy efficiency formula
19 rate, the Commission shall with reasonable notice,
20 initiate a proceeding concerning whether the projected
21 costs to be incurred by the utility and recovered during
22 the applicable rate year, and that are reflected in the
23 inputs to the energy efficiency formula rate, are
24 consistent with the utility's approved multi-year plan
25 under subsections (f) and (g) of this Section and whether
26 the costs incurred by the utility during the prior rate

1 year were prudent and reasonable. The Commission shall
2 also have the authority to investigate the information and
3 data described in paragraph (9) of subsection (g) of this
4 Section, including the proposed adjustment to the
5 utility's return on equity component of its weighted
6 average cost of capital. During the course of the
7 proceeding, each objection shall be stated with
8 particularity and evidence provided in support thereof,
9 after which the utility shall have the opportunity to
10 rebut the evidence. Discovery shall be allowed consistent
11 with the Commission's Rules of Practice, which Rules of
12 Practice shall be enforced by the Commission or the
13 assigned administrative law judge. The Commission shall
14 apply the same evidentiary standards, including, but not
15 limited to, those concerning the prudence and
16 reasonableness of the costs incurred by the utility,
17 during the proceeding as it would apply in a proceeding to
18 review a filing for a general increase in rates under
19 Article IX of this Act. The Commission shall not, however,
20 have the authority in a proceeding under this paragraph
21 (3) to consider or order any changes to the structure or
22 protocols of the energy efficiency formula rate approved
23 under paragraph (2) of this subsection (d). In a
24 proceeding under this paragraph (3), the Commission shall
25 enter its order no later than the earlier of 195 days after
26 the utility's filing of its annual update of cost inputs

1 to the energy efficiency formula rate or December 15. The
2 utility's proposed return on equity calculation, as
3 described in paragraphs (7) through (9) of subsection (g)
4 of this Section, shall be deemed the final, approved
5 calculation on December 15 of the year in which it is filed
6 unless the Commission enters an order on or before
7 December 15, after notice and hearing, that modifies such
8 calculation consistent with this Section. The Commission's
9 determinations of the prudence and reasonableness of the
10 costs incurred, and determination of such return on equity
11 calculation, for the applicable calendar year shall be
12 final upon entry of the Commission's order and shall not
13 be subject to reopening, reexamination, or collateral
14 attack in any other Commission proceeding, case, docket,
15 order, rule, or regulation; however, nothing in this
16 paragraph (3) shall prohibit a party from petitioning the
17 Commission to rehear or appeal to the courts the order
18 under the provisions of this Act.

19 (e) Beginning on June 1, 2017 (the effective date of
20 Public Act 99-906), a utility subject to the requirements of
21 this Section may elect to defer, as a regulatory asset, up to
22 the full amount of its expenditures incurred under this
23 Section for each annual period, including, but not limited to,
24 any expenditures incurred above the funding level set by
25 subsection (f) of this Section for a given year. The total
26 expenditures deferred as a regulatory asset in a given year

1 shall be amortized and recovered over a period that is equal to
2 the weighted average of the energy efficiency measure lives
3 implemented for that year that are reflected in the regulatory
4 asset. The unamortized balance shall be recognized as of
5 December 31 for a given year. The utility shall also earn a
6 return on the total of the unamortized balances of all of the
7 energy efficiency regulatory assets, less any deferred taxes
8 related to those unamortized balances, at an annual rate equal
9 to the utility's weighted average cost of capital that
10 includes, based on a year-end capital structure, the utility's
11 actual cost of debt for the applicable calendar year and a cost
12 of equity, which shall be calculated in accordance with the
13 calculations set forth in subparagraph (C) of paragraph (2) of
14 subsection (d) of this Section ~~as the sum of the (i) the~~
15 ~~average for the applicable calendar year of the monthly~~
16 ~~average yields of 30 year U.S. Treasury bonds published by the~~
17 ~~Board of Governors of the Federal Reserve System in its weekly~~
18 ~~H.15 Statistical Release or successor publication; and (ii)~~
19 ~~500 basis points~~, including a revenue conversion factor
20 calculated to recover or refund all additional income taxes
21 that may be payable or receivable as a result of that return.
22 Capital investment costs shall be depreciated and recovered
23 over their useful lives consistent with generally accepted
24 accounting principles. The weighted average cost of capital
25 shall be applied to the capital investment cost balance, less
26 any accumulated depreciation and accumulated deferred income

1 taxes, as of December 31 for a given year.

2 When an electric utility creates a regulatory asset under
3 the provisions of this Section, the costs are recovered over a
4 period during which customers also receive a benefit which is
5 in the public interest. Accordingly, it is the intent of the
6 General Assembly that an electric utility that elects to
7 create a regulatory asset under the provisions of this Section
8 shall recover all of the associated costs as set forth in this
9 Section. After the Commission has approved the prudence and
10 reasonableness of the costs that comprise the regulatory
11 asset, the electric utility shall be permitted to recover all
12 such costs, and the value and recoverability through rates of
13 the associated regulatory asset shall not be limited, altered,
14 impaired, or reduced.

15 (f) Beginning in 2017, each electric utility shall file an
16 energy efficiency plan with the Commission to meet the energy
17 efficiency standards for the next applicable multi-year period
18 beginning January 1 of the year following the filing,
19 according to the schedule set forth in paragraphs (1) through
20 (3) of this subsection (f). If a utility does not file such a
21 plan on or before the applicable filing deadline for the plan,
22 it shall face a penalty of \$100,000 per day until the plan is
23 filed.

24 (1) No later than 30 days after June 1, 2017 (the
25 effective date of Public Act 99-906), each electric
26 utility shall file a 4-year energy efficiency plan

1 commencing on January 1, 2018 that is designed to achieve
2 the cumulative persisting annual savings goals specified
3 in paragraphs (1) through (4) of subsection (b-5) of this
4 Section or in paragraphs (1) through (4) of subsection
5 (b-15) of this Section, as applicable, through
6 implementation of energy efficiency measures; however, the
7 goals may be reduced if the utility's expenditures are
8 limited pursuant to subsection (m) of this Section or, for
9 a utility that serves less than 3,000,000 retail
10 customers, if each of the following conditions are met:
11 (A) the plan's analysis and forecasts of the utility's
12 ability to acquire energy savings demonstrate that
13 achievement of such goals is not cost effective; and (B)
14 the amount of energy savings achieved by the utility as
15 determined by the independent evaluator for the most
16 recent year for which savings have been evaluated
17 preceding the plan filing was less than the average annual
18 amount of savings required to achieve the goals for the
19 applicable 4-year plan period. Except as provided in
20 subsection (m) of this Section, annual increases in
21 cumulative persisting annual savings goals during the
22 applicable 4-year plan period shall not be reduced to
23 amounts that are less than the maximum amount of
24 cumulative persisting annual savings that is forecast to
25 be cost-effectively achievable during the 4-year plan
26 period. The Commission shall review any proposed goal

1 reduction as part of its review and approval of the
2 utility's proposed plan.

3 (2) No later than March 1, 2021, each electric utility
4 shall file a 4-year energy efficiency plan commencing on
5 January 1, 2022 that is designed to achieve the cumulative
6 persisting annual savings goals specified in paragraphs
7 (5) through (8) of subsection (b-5) of this Section or in
8 paragraphs (5) through (8) of subsection (b-15) of this
9 Section, as applicable, through implementation of energy
10 efficiency measures; however, the goals may be reduced if
11 the utility's expenditures are limited pursuant to
12 subsection (m) of this Section or, each of the following
13 conditions are met: (A) the plan's analysis and forecasts
14 of the utility's ability to acquire energy savings
15 demonstrate that achievement of such goals is not cost
16 effective; and (B) the amount of energy savings achieved
17 by the utility as determined by the independent evaluator
18 for the most recent year for which savings have been
19 evaluated preceding the plan filing was less than the
20 average annual amount of savings required to achieve the
21 goals for the applicable 4-year plan period. Except as
22 provided in subsection (m) of this Section, annual
23 increases in cumulative persisting annual savings goals
24 during the applicable 4-year plan period shall not be
25 reduced to amounts that are less than the maximum amount
26 of cumulative persisting annual savings that is forecast

1 to be cost-effectively achievable during the 4-year plan
2 period. The Commission shall review any proposed goal
3 reduction as part of its review and approval of the
4 utility's proposed plan.

5 (3) No later than March 1, 2025, each electric utility
6 shall file a 5-year energy efficiency plan commencing on
7 January 1, 2026 that is designed to achieve the cumulative
8 persisting annual savings goals specified in paragraphs
9 (9) through (13) of subsection (b-5) of this Section or in
10 paragraphs (9) through (13) of subsection (b-15) of this
11 Section, as applicable, through implementation of energy
12 efficiency measures; however, the goals may be reduced if
13 the utility's expenditures are limited pursuant to
14 subsection (m) of this Section or, each of the following
15 conditions are met: (A) the plan's analysis and forecasts
16 of the utility's ability to acquire energy savings
17 demonstrate that achievement of such goals is not cost
18 effective; and (B) the amount of energy savings achieved
19 by the utility as determined by the independent evaluator
20 for the most recent year for which savings have been
21 evaluated preceding the plan filing was less than the
22 average annual amount of savings required to achieve the
23 goals for the applicable 5-year plan period. Except as
24 provided in subsection (m) of this Section, annual
25 increases in cumulative persisting annual savings goals
26 during the applicable 5-year plan period shall not be

1 reduced to amounts that are less than the maximum amount
2 of cumulative persisting annual savings that is forecast
3 to be cost-effectively achievable during the 5-year plan
4 period. The Commission shall review any proposed goal
5 reduction as part of its review and approval of the
6 utility's proposed plan.

7 Each utility's plan shall set forth the utility's
8 proposals to meet the energy efficiency standards identified
9 in subsection (b-5) or (b-15), as applicable and as such
10 standards may have been modified under this subsection (f),
11 taking into account the unique circumstances of the utility's
12 service territory. For those plans commencing on January 1,
13 2018, the Commission shall seek public comment on the
14 utility's plan and shall issue an order approving or
15 disapproving each plan no later than 105 days after June 1,
16 2017 (the effective date of Public Act 99-906). For those
17 plans commencing after December 31, 2021, the Commission shall
18 seek public comment on the utility's plan and shall issue an
19 order approving or disapproving each plan within 6 months
20 after its submission. If the Commission disapproves a plan,
21 the Commission shall, within 30 days, describe in detail the
22 reasons for the disapproval and describe a path by which the
23 utility may file a revised draft of the plan to address the
24 Commission's concerns satisfactorily. If the utility does not
25 refile with the Commission within 60 days, the utility shall
26 be subject to penalties at a rate of \$100,000 per day until the

1 plan is filed. This process shall continue, and penalties
2 shall accrue, until the utility has successfully filed a
3 portfolio of energy efficiency and demand-response measures.
4 Penalties shall be deposited into the Energy Efficiency Trust
5 Fund.

6 (g) In submitting proposed plans and funding levels under
7 subsection (f) of this Section to meet the savings goals
8 identified in subsection (b-5) or (b-15) of this Section, as
9 applicable, the utility shall:

10 (1) Demonstrate that its proposed energy efficiency
11 measures will achieve the applicable requirements that are
12 identified in subsection (b-5) or (b-15) of this Section,
13 as modified by subsection (f) of this Section.

14 (2) Present specific proposals to implement new
15 building and appliance standards that have been placed
16 into effect.

17 (3) Demonstrate that its overall portfolio of
18 measures, not including low-income programs described in
19 subsection (c) of this Section, is cost-effective using
20 the total resource cost test or complies with paragraphs
21 (1) through (3) of subsection (f) of this Section and
22 represents a diverse cross-section of opportunities for
23 customers of all rate classes, other than those customers
24 described in subsection (1) of this Section, to
25 participate in the programs. Individual measures need not
26 be cost effective.

1 (4) Present a third-party energy efficiency
2 implementation program subject to the following
3 requirements:

4 (A) beginning with the year commencing January 1,
5 2019, electric utilities that serve more than
6 3,000,000 retail customers in the State shall fund
7 third-party energy efficiency programs in an amount
8 that is no less than \$25,000,000 per year, and
9 electric utilities that serve less than 3,000,000
10 retail customers but more than 500,000 retail
11 customers in the State shall fund third-party energy
12 efficiency programs in an amount that is no less than
13 \$8,350,000 per year;

14 (B) during 2018, the utility shall conduct a
15 solicitation process for purposes of requesting
16 proposals from third-party vendors for those
17 third-party energy efficiency programs to be offered
18 during one or more of the years commencing January 1,
19 2019, January 1, 2020, and January 1, 2021; for those
20 multi-year plans commencing on January 1, 2022 and
21 January 1, 2026, the utility shall conduct a
22 solicitation process during 2021 and 2025,
23 respectively, for purposes of requesting proposals
24 from third-party vendors for those third-party energy
25 efficiency programs to be offered during one or more
26 years of the respective multi-year plan period; for

1 each solicitation process, the utility shall identify
2 the sector, technology, or geographical area for which
3 it is seeking requests for proposals;

4 (C) the utility shall propose the bidder
5 qualifications, performance measurement process, and
6 contract structure, which must include a performance
7 payment mechanism and general terms and conditions;
8 the proposed qualifications, process, and structure
9 shall be subject to Commission approval; and

10 (D) the utility shall retain an independent third
11 party to score the proposals received through the
12 solicitation process described in this paragraph (4),
13 rank them according to their cost per lifetime
14 kilowatt-hours saved, and assemble the portfolio of
15 third-party programs.

16 The electric utility shall recover all costs
17 associated with Commission-approved, third-party
18 administered programs regardless of the success of those
19 programs.

20 (4.5) Implement cost-effective demand-response
21 measures to reduce peak demand by 0.1% over the prior year
22 for eligible retail customers, as defined in Section
23 16-111.5 of this Act, and for customers that elect hourly
24 service from the utility pursuant to Section 16-107 of
25 this Act, provided those customers have not been declared
26 competitive. This requirement continues until December 31,

1 2026.

2 (5) Include a proposed or revised cost-recovery tariff
3 mechanism, as provided for under subsection (d) of this
4 Section, to fund the proposed energy efficiency and
5 demand-response measures and to ensure the recovery of the
6 prudently and reasonably incurred costs of
7 Commission-approved programs.

8 (6) Provide for an annual independent evaluation of
9 the performance of the cost-effectiveness of the utility's
10 portfolio of measures, as well as a full review of the
11 multi-year plan results of the broader net program impacts
12 and, to the extent practical, for adjustment of the
13 measures on a going-forward basis as a result of the
14 evaluations. For purposes of evaluating the
15 cost-effectiveness of measures that incentivize,
16 encourage, or otherwise support the purchase of vehicles
17 that use electricity for power, in whole or in part,
18 including, but not limited to, cars, trucks, buses,
19 trains, trolleys, boats, on-road or off-road vehicles, or
20 other equipment or methods of transporting goods or
21 people, including, but not limited to, measures that
22 incentivize, encourage, or otherwise support the adoption
23 of electric vehicles by retail customers of all customer
24 classes, the independent evaluation shall include
25 valuation and consideration of the reduction of carbon
26 emissions and avoided costs associated with the reduction

1 in fossil fuel consumption associated with the measures.

2 The resources dedicated to evaluation shall not exceed 3%
3 of portfolio resources in any given year.

4 (7) For electric utilities that serve more than
5 3,000,000 retail customers in the State:

6 (A) Through December 31, 2025, provide for an
7 adjustment to the return on equity component of the
8 utility's weighted average cost of capital calculated
9 under subsection (d) of this Section:

10 (i) If the independent evaluator determines
11 that the utility achieved a cumulative persisting
12 annual savings that is less than the applicable
13 annual incremental goal, then the return on equity
14 component shall be reduced by a maximum of 200
15 basis points in the event that the utility
16 achieved no more than 75% of such goal. If the
17 utility achieved more than 75% of the applicable
18 annual incremental goal but less than 100% of such
19 goal, then the return on equity component shall be
20 reduced by 8 basis points for each percent by
21 which the utility failed to achieve the goal.

22 (ii) If the independent evaluator determines
23 that the utility achieved a cumulative persisting
24 annual savings that is more than the applicable
25 annual incremental goal, then the return on equity
26 component shall be increased by a maximum of 200

1 basis points in the event that the utility
2 achieved at least 125% of such goal. If the
3 utility achieved more than 100% of the applicable
4 annual incremental goal but less than 125% of such
5 goal, then the return on equity component shall be
6 increased by 8 basis points for each percent by
7 which the utility achieved above the goal. If the
8 applicable annual incremental goal was reduced
9 under paragraphs (1) or (2) of subsection (f) of
10 this Section, then the following adjustments shall
11 be made to the calculations described in this item
12 (ii):

13 (aa) the calculation for determining
14 achievement that is at least 125% of the
15 applicable annual incremental goal shall use
16 the unreduced applicable annual incremental
17 goal to set the value; and

18 (bb) the calculation for determining
19 achievement that is less than 125% but more
20 than 100% of the applicable annual incremental
21 goal shall use the reduced applicable annual
22 incremental goal to set the value for 100%
23 achievement of the goal and shall use the
24 unreduced goal to set the value for 125%
25 achievement. The 8 basis point value shall
26 also be modified, as necessary, so that the

1 200 basis points are evenly apportioned among
2 each percentage point value between 100% and
3 125% achievement.

4 (B) For the period January 1, 2026 through
5 December 31, 2030, provide for an adjustment to the
6 return on equity component of the utility's weighted
7 average cost of capital calculated under subsection
8 (d) of this Section:

9 (i) If the independent evaluator determines
10 that the utility achieved a cumulative persisting
11 annual savings that is less than the applicable
12 annual incremental goal, then the return on equity
13 component shall be reduced by a maximum of 200
14 basis points in the event that the utility
15 achieved no more than 66% of such goal. If the
16 utility achieved more than 66% of the applicable
17 annual incremental goal but less than 100% of such
18 goal, then the return on equity component shall be
19 reduced by 6 basis points for each percent by
20 which the utility failed to achieve the goal.

21 (ii) If the independent evaluator determines
22 that the utility achieved a cumulative persisting
23 annual savings that is more than the applicable
24 annual incremental goal, then the return on equity
25 component shall be increased by a maximum of 200
26 basis points in the event that the utility

1 achieved at least 134% of such goal. If the
2 utility achieved more than 100% of the applicable
3 annual incremental goal but less than 134% of such
4 goal, then the return on equity component shall be
5 increased by 6 basis points for each percent by
6 which the utility achieved above the goal. If the
7 applicable annual incremental goal was reduced
8 under paragraph (3) of subsection (f) of this
9 Section, then the following adjustments shall be
10 made to the calculations described in this item
11 (ii):

12 (aa) the calculation for determining
13 achievement that is at least 134% of the
14 applicable annual incremental goal shall use
15 the unreduced applicable annual incremental
16 goal to set the value; and

17 (bb) the calculation for determining
18 achievement that is less than 134% but more
19 than 100% of the applicable annual incremental
20 goal shall use the reduced applicable annual
21 incremental goal to set the value for 100%
22 achievement of the goal and shall use the
23 unreduced goal to set the value for 134%
24 achievement. The 6 basis point value shall
25 also be modified, as necessary, so that the
26 200 basis points are evenly apportioned among

1 each percentage point value between 100% and
2 134% achievement.

3 (7.5) For purposes of this Section, the term
4 "applicable annual incremental goal" means the difference
5 between the cumulative persisting annual savings goal for
6 the calendar year that is the subject of the independent
7 evaluator's determination and the cumulative persisting
8 annual savings goal for the immediately preceding calendar
9 year, as such goals are defined in subsections (b-5) and
10 (b-15) of this Section and as these goals may have been
11 modified as provided for under subsection (b-20) and
12 paragraphs (1) through (3) of subsection (f) of this
13 Section. Under subsections (b), (b-5), (b-10), and (b-15)
14 of this Section, a utility must first replace energy
15 savings from measures that have reached the end of their
16 measure lives and would otherwise have to be replaced to
17 meet the applicable savings goals identified in subsection
18 (b-5) or (b-15) of this Section before any progress
19 towards achievement of its applicable annual incremental
20 goal may be counted. Notwithstanding anything else set
21 forth in this Section, the difference between the actual
22 annual incremental savings achieved in any given year,
23 including the replacement of energy savings from measures
24 that have expired, and the applicable annual incremental
25 goal shall not affect adjustments to the return on equity
26 for subsequent calendar years under this subsection (g).

1 (8) For electric utilities that serve less than
2 3,000,000 retail customers but more than 500,000 retail
3 customers in the State:

4 (A) Through December 31, 2025, the applicable
5 annual incremental goal shall be compared to the
6 annual incremental savings as determined by the
7 independent evaluator.

8 (i) The return on equity component shall be
9 reduced by 8 basis points for each percent by
10 which the utility did not achieve 84.4% of the
11 applicable annual incremental goal.

12 (ii) The return on equity component shall be
13 increased by 8 basis points for each percent by
14 which the utility exceeded 100% of the applicable
15 annual incremental goal.

16 (iii) The return on equity component shall not
17 be increased or decreased if the annual
18 incremental savings as determined by the
19 independent evaluator is greater than 84.4% of the
20 applicable annual incremental goal and less than
21 100% of the applicable annual incremental goal.

22 (iv) The return on equity component shall not
23 be increased or decreased by an amount greater
24 than 200 basis points pursuant to this
25 subparagraph (A).

26 (B) For the period of January 1, 2026 through

1 December 31, 2030, the applicable annual incremental
2 goal shall be compared to the annual incremental
3 savings as determined by the independent evaluator.

4 (i) The return on equity component shall be
5 reduced by 6 basis points for each percent by
6 which the utility did not achieve 100% of the
7 applicable annual incremental goal.

8 (ii) The return on equity component shall be
9 increased by 6 basis points for each percent by
10 which the utility exceeded 100% of the applicable
11 annual incremental goal.

12 (iii) The return on equity component shall not
13 be increased or decreased by an amount greater
14 than 200 basis points pursuant to this
15 subparagraph (B).

16 (C) If the applicable annual incremental goal was
17 reduced under paragraphs (1), (2) or (3) of subsection
18 (f) of this Section, then the following adjustments
19 shall be made to the calculations described in
20 subparagraphs (A) and (B) of this paragraph (8):

21 (i) The calculation for determining
22 achievement that is at least 125% or 134%, as
23 applicable, of the applicable annual incremental
24 goal shall use the unreduced applicable annual
25 incremental goal to set the value.

26 (ii) For the period through December 31, 2025,

1 the calculation for determining achievement that
2 is less than 125% but more than 100% of the
3 applicable annual incremental goal shall use the
4 reduced applicable annual incremental goal to set
5 the value for 100% achievement of the goal and
6 shall use the unreduced goal to set the value for
7 125% achievement. The 8 basis point value shall
8 also be modified, as necessary, so that the 200
9 basis points are evenly apportioned among each
10 percentage point value between 100% and 125%
11 achievement.

12 (iii) For the period of January 1, 2026
13 through December 31, 2030, the calculation for
14 determining achievement that is less than 134% but
15 more than 100% of the applicable annual
16 incremental goal shall use the reduced applicable
17 annual incremental goal to set the value for 100%
18 achievement of the goal and shall use the
19 unreduced goal to set the value for 125%
20 achievement. The 6 basis point value shall also be
21 modified, as necessary, so that the 200 basis
22 points are evenly apportioned among each
23 percentage point value between 100% and 134%
24 achievement.

25 (8.5) Electric utilities that serve less than
26 3,000,000 retail customers but more than 500,000 retail

1 customers in this State may identify, at the electric
2 utility's sole discretion, cost-effective measures that
3 educate about, incentivize, encourage, or otherwise
4 support the use of electricity to power, in whole or in
5 part, vehicles, including, but not limited to, cars,
6 trucks, buses, trains, trolleys, boats, on-road or
7 off-road vehicles, or other equipment or methods of
8 transporting goods or people. Such measures may include,
9 but are not limited to, measures that educate about,
10 incentivize, encourage, or otherwise support the adoption
11 of electric vehicles by retail customers of all rate
12 classes.

13 (9) The utility shall submit the energy savings data
14 to the independent evaluator no later than 30 days after
15 the close of the plan year. The independent evaluator
16 shall determine the cumulative persisting annual savings
17 for a given plan year no later than 120 days after the
18 close of the plan year. The utility shall submit an
19 informational filing to the Commission no later than 160
20 days after the close of the plan year that attaches the
21 independent evaluator's final report identifying the
22 cumulative persisting annual savings for the year and
23 calculates, under paragraph (7) or (8) of this subsection
24 (g), as applicable, any resulting change to the utility's
25 return on equity component of the weighted average cost of
26 capital applicable to the next plan year beginning with

1 the January monthly billing period and extending through
2 the December monthly billing period. However, if the
3 utility recovers the costs incurred under this Section
4 under paragraphs (2) and (3) of subsection (d) of this
5 Section, then the utility shall not be required to submit
6 such informational filing, and shall instead submit the
7 information that would otherwise be included in the
8 informational filing as part of its filing under paragraph
9 (3) of such subsection (d) that is due on or before June 1
10 of each year.

11 For those utilities that must submit the informational
12 filing, the Commission may, on its own motion or by
13 petition, initiate an investigation of such filing,
14 provided, however, that the utility's proposed return on
15 equity calculation shall be deemed the final, approved
16 calculation on December 15 of the year in which it is filed
17 unless the Commission enters an order on or before
18 December 15, after notice and hearing, that modifies such
19 calculation consistent with this Section.

20 The adjustments to the return on equity component
21 described in paragraphs (7) and (8) of this subsection (g)
22 shall be applied as described in such paragraphs through a
23 separate tariff mechanism, which shall be filed by the
24 utility under subsections (f) and (g) of this Section.

25 (h) Other than measures authorized by subsection (n) of
26 this Section or identified pursuant to paragraph (8.5) of

1 subsection (g) of this Section, no ~~no~~ more than 6% of energy
2 efficiency and demand-response program revenue may be
3 allocated for research, development, or pilot deployment of
4 new equipment or measures.

5 (i) When practicable, electric utilities shall incorporate
6 advanced metering infrastructure data into the planning,
7 implementation, and evaluation of energy efficiency measures
8 and programs, subject to the data privacy and confidentiality
9 protections of applicable law.

10 (j) The independent evaluator shall follow the guidelines
11 and use the savings set forth in Commission-approved energy
12 efficiency policy manuals and technical reference manuals, as
13 each may be updated from time to time. Until such time as
14 measure life values for energy efficiency measures implemented
15 for low-income households under subsection (c) of this Section
16 are incorporated into such Commission-approved manuals, the
17 low-income measures shall have the same measure life values
18 that are established for same measures implemented in
19 households that are not low-income households.

20 Commencing on the effective date of this amendatory Act of
21 the 102nd General Assembly, the following provisions shall
22 apply to electric utilities that serve less than 3,000,000
23 retail customers but more than 500,000 retail customers in
24 this State:

25 (1) Starting in the year in which this amendatory Act
26 of the 102nd General Assembly takes effect and continuing

1 for a period of 5 calendar years thereafter, the savings
2 achieved by energy efficiency measures authorized by
3 subsection (n) of this Section or identified pursuant to
4 paragraph (8.5) of subsection (g) of this Section, shall
5 be evaluated using the following parameters:

6 (A) the evaluation shall use a factor of 1.50
7 pounds of carbon dioxide emitted per kilowatt hour of
8 electric energy used for vehicle operation, adjusted
9 each year starting with the year in which this
10 amendatory Act of the 102nd General Assembly takes
11 effect to reflect the annual increase of renewable
12 resource procurement as set forth in subsection (c) of
13 Section 1-75 of the Illinois Power Agency Act;

14 (B) the evaluation shall use a heat rate of fossil
15 fuel electric generating units of 7,939 Btu per
16 kilowatt hour, adjusted each year starting with the
17 year in which this amendatory Act of the 102nd General
18 Assembly takes effect to reflect the annual increase
19 of renewable resource procurement as set forth in
20 subsection (c) of Section 1-75 of the Illinois Power
21 Agency Act;

22 (C) the evaluation shall include any netting of
23 electricity used by the electric vehicle, as
24 calculated using the parameters provided for in
25 paragraph (2) of this subsection (j);

26 (D) the evaluation shall use a net to gross ratio

1 of 1.0 for each measure evaluated; and

2 (E) all savings achieved by the measures evaluated
3 shall persist for the life of the measure, without
4 degradation.

5 (2) Starting in the year in which this amendatory Act
6 of the 102nd General Assembly takes effect and continuing
7 for a period of 5 calendar years thereafter, the savings
8 achieved by energy efficiency measures authorized by
9 subsection (n) of this Section or identified pursuant to
10 paragraph (8.5) of subsection (g) of this Section that are
11 applicable to passenger vehicles shall, in addition to the
12 parameters identified in paragraph (1) of this subsection
13 (j), be evaluated using the following parameters:

14 (A) the measure life of measures that incentivize
15 or otherwise encourage the purchase of electric
16 vehicles shall be 13 years from the date of original
17 purchase by the customer;

18 (B) the evaluation shall use a value of 11,500
19 vehicle miles traveled for annual vehicle operation;

20 (C) the evaluation shall use a fossil fuel vehicle
21 economy value equal to 28 miles per gallon of fossil
22 fuel used for vehicle operation;

23 (D) the evaluation shall use a conversion factor
24 of 120,429 Btus per gallon of fossil fuel used for
25 vehicle operation;

26 (E) the evaluation shall use a factor of 161

1 pounds of carbon dioxide emitted per million Btu of
2 fossil fuel used for vehicle operation;

3 (F) the evaluation shall use a factor of 8.78
4 kilograms of carbon dioxide emitted per gallon of
5 fossil fuel used for vehicle operation;

6 (G) the evaluation shall use an annual value of
7 fossil fuel saved of 50 MMBtu; and

8 (H) the evaluation shall use an electric vehicle
9 efficiency value of 30 kilowatt hours per 100 miles
10 traveled for vehicle operation.

11 (3) Any additional evaluation criteria not identified
12 in paragraph (1) or (2) of this subsection (j) used to
13 evaluate savings achieved by energy efficiency measures
14 authorized by subsection (n) of this Section or identified
15 pursuant to paragraph (8.5) of subsection (g) of this
16 Section shall follow the guidelines and use the savings
17 set forth in Commission-approved energy efficiency policy
18 manuals and technical reference manuals, as each may be
19 updated from time to time.

20 (k) Notwithstanding any provision of law to the contrary,
21 an electric utility subject to the requirements of this
22 Section may file a tariff cancelling an automatic adjustment
23 clause tariff in effect under this Section or Section 8-103,
24 which shall take effect no later than one business day after
25 the date such tariff is filed. Thereafter, the utility shall
26 be authorized to defer and recover its expenditures incurred

1 under this Section through a new tariff authorized under
2 subsection (d) of this Section or in the utility's next rate
3 case under Article IX or Section 16-108.5 of this Act, with
4 interest at an annual rate equal to the utility's weighted
5 average cost of capital as approved by the Commission in such
6 case. If the utility elects to file a new tariff under
7 subsection (d) of this Section, the utility may file the
8 tariff within 10 days after June 1, 2017 (the effective date of
9 Public Act 99-906), and the cost inputs to such tariff shall be
10 based on the projected costs to be incurred by the utility
11 during the calendar year in which the new tariff is filed and
12 that were not recovered under the tariff that was cancelled as
13 provided for in this subsection. Such costs shall include
14 those incurred or to be incurred by the utility under its
15 multi-year plan approved under subsections (f) and (g) of this
16 Section, including, but not limited to, projected capital
17 investment costs and projected regulatory asset balances with
18 correspondingly updated depreciation and amortization reserves
19 and expense. The Commission shall, after notice and hearing,
20 approve, or approve with modification, such tariff and cost
21 inputs no later than 75 days after the utility filed the
22 tariff, provided that such approval, or approval with
23 modification, shall be consistent with the provisions of this
24 Section to the extent they do not conflict with this
25 subsection (k). The tariff approved by the Commission shall
26 take effect no later than 5 days after the Commission enters

1 its order approving the tariff.

2 No later than 60 days after the effective date of the
3 tariff cancelling the utility's automatic adjustment clause
4 tariff, the utility shall file a reconciliation that
5 reconciles the moneys collected under its automatic adjustment
6 clause tariff with the costs incurred during the period
7 beginning June 1, 2016 and ending on the date that the electric
8 utility's automatic adjustment clause tariff was cancelled. In
9 the event the reconciliation reflects an under-collection, the
10 utility shall recover the costs as specified in this
11 subsection (k). If the reconciliation reflects an
12 over-collection, the utility shall apply the amount of such
13 over-collection as a one-time credit to retail customers'
14 bills.

15 (l) For the calendar years covered by a multi-year plan
16 commencing after December 31, 2017, subsections (a) through
17 (j) of this Section do not apply to any retail customers of an
18 electric utility that serves more than 3,000,000 retail
19 customers in the State and whose total highest 30 minute
20 demand was more than 10,000 kilowatts, or any retail customers
21 of an electric utility that serves less than 3,000,000 retail
22 customers but more than 500,000 retail customers in the State
23 and whose total highest 15 minute demand was more than 10,000
24 kilowatts. For purposes of this subsection (l), "retail
25 customer" has the meaning set forth in Section 16-102 of this
26 Act. A determination of whether this subsection is applicable

1 to a customer shall be made for each multi-year plan beginning
2 after December 31, 2017. The criteria for determining whether
3 this subsection (l) is applicable to a retail customer shall
4 be based on the 12 consecutive billing periods prior to the
5 start of the first year of each such multi-year plan.

6 (m) Notwithstanding the requirements of this Section, as
7 part of a proceeding to approve a multi-year plan under
8 subsections (f) and (g) of this Section, the Commission shall
9 reduce the amount of energy efficiency measures implemented
10 for any single year, and whose costs are recovered under
11 subsection (d) of this Section, by an amount necessary to
12 limit the estimated average net increase due to the cost of the
13 measures to no more than

14 (1) 3.5% for each of the 4 years beginning January 1,
15 2018,

16 (2) 3.75% for each of the 4 years beginning January 1,
17 2022, and

18 (3) 4% for each of the 5 years beginning January 1,
19 2026,

20 of the average amount paid per kilowatthour by residential
21 eligible retail customers during calendar year 2015. To
22 determine the total amount that may be spent by an electric
23 utility in any single year, the applicable percentage of the
24 average amount paid per kilowatthour shall be multiplied by
25 the total amount of energy delivered by such electric utility
26 in the calendar year 2015, adjusted to reflect the proportion

1 of the utility's load attributable to customers who are exempt
2 from subsections (a) through (j) of this Section under
3 subsection (l) of this Section. For purposes of this
4 subsection (m), the amount paid per kilowatthour includes,
5 without limitation, estimated amounts paid for supply,
6 transmission, distribution, surcharges, and add-on taxes. For
7 purposes of this Section, "eligible retail customers" shall
8 have the meaning set forth in Section 16-111.5 of this Act.
9 Once the Commission has approved a plan under subsections (f)
10 and (g) of this Section, no subsequent rate impact
11 determinations shall be made.

12 (n) Starting on the effective date of this amendatory Act
13 of the 102nd General Assembly, electric utilities that serve
14 less than 3,000,000 retail customers but more than 500,000
15 retail customers in this State may administer programs and
16 implement cost-effective measures that educate about,
17 incentivize, encourage, or otherwise support the use of
18 electricity to power, in whole or in part, vehicles,
19 including, but not limited to, cars, trucks, buses, trains,
20 trolleys, boats, on-road or off-road vehicles, or other
21 equipment or methods of transporting goods or people. Such
22 programs and measures may be implemented as part of a plan
23 approved pursuant to subsection (f) of this Section and may
24 include, but are not limited to, measures that educate about,
25 incentivize, encourage, or otherwise support the adoption of
26 electric vehicles by retail customers of all customer classes.

1 Programs and measures authorized by this subsection (n) and
2 identified pursuant to paragraph (8.5) of subsection (g) shall
3 not be prohibited by the Commission as promotional practices
4 under any rules or policies of the Commission, including, but
5 not limited to, 83 Ill. Adm. Code Part 275.

6 (Source: P.A. 100-840, eff. 8-13-18; 101-81, eff. 7-12-19.)

7 (220 ILCS 5/8-218 new)

8 Sec. 8-218. Electric photovoltaic generating facilities.

9 (a) The General Assembly finds and declares that the
10 citizens and businesses of the State of Illinois would be
11 well-served by the development of photovoltaic electricity
12 production facilities in this State, which would both bring
13 economic benefits and environmental benefits to the State and
14 further expand access to renewable energy resources at an
15 affordable cost to Illinois residents, particularly in those
16 areas of the State that have been significantly and adversely
17 affected by the retirement of coal-fired electric generating
18 plants. To that end, the General Assembly seeks to encourage
19 further development of photovoltaic electric production
20 facilities of all scales in an efficient and cost-effective
21 manner. Accordingly, the General Assembly finds that,
22 notwithstanding other provisions of this Act to the contrary,
23 it would be both prudent and reasonable for electric utilities
24 in this State to plan for, construct, install, control, own,
25 manage, or operate photovoltaic electricity production

1 facilities pursuant to the provisions of this Section.

2 (b) An electric utility that serves less than 3,000,000
3 retail customers but more than 500,000 customers in this
4 State, may plan for, construct, install, control, own, manage,
5 or operate photovoltaic electricity production facilities and
6 any energy storage facilities as authorized under Section
7 16-108.20 of this Act that are planned for, constructed,
8 installed, controlled, owned, managed, or operated in
9 connection with photovoltaic electricity production facilities
10 authorized under this Section without obtaining a certificate
11 of public convenience and necessity pursuant to Section 8-406
12 of this Act, subject to the following terms and conditions:

13 (1) the electric utility may plan for, construct,
14 install, control, own, manage, or operate photovoltaic
15 electricity production facilities of any type or scale,
16 including, but not limited to, large scale (greater than 2
17 MW), small scale (less than or equal to 2 MW), and
18 community solar projects; for purposes of this Section,
19 "community solar projects" includes community solar
20 facilities with a nameplate capacity up to and including
21 10,000 kilowatts that are connected to either the
22 distribution system or transmission system of the electric
23 utility;

24 (2) photovoltaic electricity production facilities
25 authorized pursuant to this Section shall be deemed for
26 all purposes under this Act as prudent and used and

1 useful, including under the provisions of Section 9-212 of
2 this Act, and, subject to the provisions set forth in this
3 Section, the Commission may not limit recovery of any
4 portion of the reasonable costs of the photovoltaic
5 electricity production facilities authorized pursuant to
6 this Section on the grounds that the facilities are not
7 prudent or used and useful;

8 (3) the electric utility's costs of planning for,
9 constructing, installing, controlling, owning, managing,
10 or operating the photovoltaic electricity production
11 facilities shall be recovered, on a kilowatt hour basis,
12 in the electric utility's rates for delivery service
13 established pursuant to Article XVI or Article IX of this
14 Act, and for purposes of cost recovery the photovoltaic
15 electricity production facilities, shall be treated as
16 distribution assets, provided: (1) the Commission shall
17 have the authority to determine the reasonableness of the
18 costs of the facilities, (2) any monetary value of power
19 and energy from the facilities shall be credited against
20 the delivery services revenue requirement, and (3) all
21 renewable energy credits associated with the photovoltaic
22 electricity production facilities shall be retired on
23 behalf of the electric utility's distribution customers
24 and may not be sold or used for any other purposes by the
25 electric utility other than satisfying the electric
26 utility's requirements under subsection (c) of Section

1 1-75 of the Illinois Power Agency Act;

2 (4) the annual quantity of renewable energy credits
3 generated from the photovoltaic electricity production
4 facilities placed in service by an electric utility
5 pursuant to this Section after the effective date of this
6 amendatory Act of the 102nd General Assembly shall not
7 exceed 20% of the electric utility's requirements under
8 subsection (c) of Section 1-75 of the Illinois Power
9 Agency Act; and

10 (5) the electric utility shall certify that not less
11 than the prevailing wage, as determined pursuant to the
12 Prevailing Wage Act, was or will be paid to employees who
13 are engaged in construction activities associated with the
14 photovoltaic electric production facilities authorized
15 under this Section.

16 If an electric utility requires approval under Section
17 7-101 or 7-102 of this Act in connection with the
18 construction, installation, control, ownership, management, or
19 operation of photovoltaic electricity production facilities
20 pursuant to this Section, the Commission shall issue its Order
21 granting or denying such approval within 150 days after a
22 petition for such approval is filed.

23 For purposes of this Section, "electric utility" has the
24 meaning set forth in Section 16-102 of this Act.

25 (c) Notwithstanding anything to the contrary in the
26 Illinois Power Agency Act or this Act, the Illinois Power

1 Agency shall apply any renewable energy credits associated
2 with photovoltaic electricity production facilities meeting
3 the criteria set forth in subsection (b) of this Section to the
4 electric utility's requirements under subsection (c) of
5 Section 1-75 of the Illinois Power Agency Act. No cost
6 associated with facilities placed in service pursuant to this
7 Section shall be included when calculating the limitation
8 under subparagraph (E) of paragraph (1) of subsection (c) of
9 Section 1-75 of the Illinois Power Agency Act.

10 (220 ILCS 5/9-244.5 new)

11 Sec. 9-244.5. Natural gas investment and modernization;
12 regulatory reform.

13 (a) The General Assembly finds that regulatory reform
14 measures that increase predictability, stability, and
15 transparency in the ratemaking process are needed to promote
16 prudent, long-term infrastructure investment and to mutually
17 benefit the State's natural gas utilities and their customers,
18 regulators, and investors.

19 (b) For purposes of this Section, "participating gas
20 utility" means a public utility that, as of January 1, 2020,
21 provided electric service to at least 1,000,000 retail
22 customers in Illinois and gas service to at least 500,000
23 retail customers in Illinois.

24 (c) A participating gas utility may elect to recover its
25 natural gas delivery services costs through a

1 performance-based rate, which shall be approved by the
2 Commission and which shall specify the cost components that
3 form the basis of the rate charged to customers with
4 sufficient specificity to operate in a standardized manner and
5 be updated annually with transparent information that reflects
6 the participating gas utility's actual costs to be recovered
7 during the applicable year, which is the period beginning with
8 the first billing day of January and extending through the
9 last billing day of the following December. In the event the
10 participating gas utility recovers a portion of its costs
11 through automatic adjustment clause tariffs on the effective
12 date of the Act, other than a surcharge tariff under paragraph
13 (3) of subsection (a) of Section 9-220.3, the participating
14 gas utility may elect to continue to recover these costs
15 through such tariffs, but such costs shall not be recovered
16 through the performance based rate as long as the
17 participating gas utility elects to recover such costs through
18 such automatic adjustment clause tariffs.

19 The performance-based rate shall be implemented through a
20 tariff filed with the Commission consistent with the
21 provisions of this subsection (c) that shall be applicable to
22 all natural gas delivery services customers. The Commission
23 shall initiate and conduct an investigation of the tariff in a
24 manner consistent with the provisions of this subsection (c)
25 and the provisions of Article IX of this Act to the extent they
26 do not conflict with this subsection (c). The

1 performance-based rate shall remain in effect at the
2 discretion of the participating gas utility.

3 The performance-based rate approved by the Commission
4 shall do the following:

5 (1) Provide for the recovery of the participating gas
6 utility's actual costs of natural gas delivery services
7 that are prudently incurred and reasonable in amount
8 consistent with Commission practice and law. The sole fact
9 that a cost differs from that incurred in a prior calendar
10 year or that an investment is different from that made in a
11 prior calendar year shall not imply the imprudence or
12 unreasonableness of that cost or investment.

13 (2) Reflect the utility's actual year-end capital
14 structure for the applicable calendar year, excluding
15 goodwill, subject to a determination of prudence and
16 reasonableness consistent with Commission practice and
17 law. To enable the financing of the incremental capital
18 expenditures, including regulatory assets, a participating
19 gas utility's actual year-end capital structure that
20 includes a common equity ratio, excluding goodwill, of up
21 to and including 54% of the total capital structure shall
22 be deemed reasonable and used to set rates.

23 (3) Include a cost of equity equal to the national
24 average cost of equity. For purposes of this paragraph (3)
25 of this subsection (c), the national average cost of
26 equity applicable to a calendar year shall be the simple

1 average of the cost of equity specified and approved in
2 each order of a state regulatory commission, other than
3 the Commission, issued during such calendar year that is
4 applicable to base rates for retail natural gas delivery
5 service provided by an investor-owned public utility
6 company operating in the United States. No order shall be
7 excluded from the national average cost of equity
8 calculated under this paragraph (3) on the grounds that it
9 was arrived at by stipulation or agreement or is subject
10 to rehearing or appeal. If, for any calendar year, there
11 are fewer than 15 applicable orders of state regulatory
12 commissions with which to compute the average cost of
13 equity, the Commission shall include in the calculation of
14 the national average the number of state regulatory orders
15 from the year or years immediately preceding such calendar
16 year necessary to reach a total of 15, beginning with the
17 most recently issued and proceeding in reverse
18 chronological order.

19 (4) Permit and set forth protocols, subject to a
20 determination of prudence and reasonableness consistent
21 with Commission practice and law, for the following:

22 (A) irrespective of the form of award, recovery of
23 expense of incentive compensation that is awarded
24 based on non-financial criteria such as the
25 achievement of operational metrics, including metrics
26 related to budget controls, safety, customer service,

1 efficiency and productivity, and environmental
2 compliance. The expense of incentive compensation
3 expense that is awarded based on net income or an
4 affiliate's earnings per share shall not be
5 recoverable under the performance-based rate;

6 (B) recovery of pension and other post-employment
7 benefits expense, provided that such costs are
8 supported by an actuarial study;

9 (C) recovery of severance costs, provided that if
10 the amount is over \$2,500,000, then the full amount
11 shall be amortized consistent with subparagraph (F) of
12 this paragraph (4);

13 (D) investment return at a rate equal to the
14 participating gas utility's weighted average cost of
15 long-term debt on the pension assets as, and in the
16 amount, reported in Account 182.3 and 186 (or in such
17 other Account or Accounts as such asset may
18 subsequently be recorded) of the utility's most
19 recently filed ICC Form 21, FERC Form 1, or FERC Form
20 2, as applicable, net of deferred tax benefits;

21 (E) recovery of the expenses related to the
22 Commission proceeding under this subsection (c) to
23 approve this performance-based rate and initial rates
24 or to subsequent proceedings related to the formula,
25 provided that the recovery shall be amortized over a
26 3-year period; recovery of expenses related to the

1 annual Commission proceedings under subsection (e) of
2 this Section to review the inputs to the
3 performance-based rate shall be expensed and recovered
4 through the performance-based rate;

5 (F) amortization over a 5-year period of the full
6 amount of each charge or credit that exceeds the
7 amount specified in subparagraph (C) of this paragraph
8 (4) and that relates to a workforce reduction
9 program's severance costs, changes in accounting
10 rules, changes in law, compliance with any
11 Commission-initiated audit, or other extraordinary
12 expense, provided that any unamortized balance shall
13 be reflected in rate base. For purposes of this
14 subparagraph (F), changes in law include any
15 enactment, repeal, or amendment in a law, ordinance,
16 rule, regulation, interpretation, permit, license,
17 consent, or order, including those relating to taxes,
18 accounting, or to environmental matters, or in the
19 interpretation or application thereof by any
20 governmental authority occurring after the effective
21 date of the Act;

22 (G) recovery of existing regulatory assets over
23 the periods previously authorized by the Commission;

24 (H) historical weather normalized billing
25 determinants; and

26 (I) allocation methods for common costs.

1 (5) Provide that if the participating gas utility's
2 earned rate of return on common equity related to the
3 provision of natural gas delivery services for the prior
4 rate year (calculated using costs and capital structure
5 approved by the Commission as provided in subparagraphs
6 (2) and (3) of this subsection (c), consistent with this
7 Section, in accordance with Commission rules and orders,
8 including, but not limited to, adjustments for goodwill,
9 and after any Commission-ordered disallowances and taxes)
10 is higher than the rate of return on common equity
11 calculated pursuant to paragraph (3) of this subsection
12 (c) (after any adjustments to the rate of return on common
13 equity applied pursuant to the performance metrics
14 provision of subsection (g) or (h) of this Section, as
15 applicable), then the participating gas utility shall
16 apply a credit through the performance-based rate that
17 reflects an amount equal to the value of that portion of
18 the earned rate of return on common equity that is higher
19 than the rate of return on common equity calculated
20 pursuant to paragraph (3) of this subsection (c) (after
21 any adjustments to the rate of return on common equity
22 applied pursuant to the performance metrics provision of
23 subsection (g) or (h) of this Section, as applicable) for
24 the prior rate year, adjusted for taxes. If the
25 participating gas utility's earned rate of return on
26 common equity related to the provision of natural gas

1 delivery services for the prior rate year (calculated
2 using costs and capital structure approved by the
3 Commission as provided in paragraphs (2) and (3) of this
4 subsection (c), consistent with this Section, in
5 accordance with Commission rules and orders, including,
6 but not limited to, adjustments for goodwill, and after
7 any Commission-ordered disallowances and taxes) is less
8 than the return on common equity calculated pursuant to
9 paragraph (3) of this subsection (c) (after any
10 adjustments to the rate of return on common equity applied
11 pursuant to the performance metrics provision of
12 subsections (g) or (h) of this Section, as applicable),
13 then the participating gas utility shall apply a charge
14 through the performance-based rate that reflects an amount
15 equal to the value of that portion of the earned rate of
16 return on common equity that is less than the rate of
17 return on common equity calculated pursuant to paragraph
18 (3) of this subsection (c) (after any adjustments to the
19 rate of return on common equity applied pursuant to the
20 performance metrics provision of subsections (g) or (h) of
21 this Section, as applicable) for the prior rate year,
22 adjusted for taxes.

23 (6) Provide for annual reconciliations, as described
24 in subsection (e) of this Section, with interest, of the
25 revenue requirement reflected in rates for each calendar
26 year, beginning with the calendar year in which the

1 participating gas utility files its performance-based rate
2 tariff pursuant to subsection (c) of this Section, with
3 what the revenue requirement would have been had the
4 actual cost information for the applicable calendar year
5 been available at the filing date.

6 (7) Any surcharge tariff of a participating gas
7 utility authorized by paragraph (3) of subsection (a) of
8 Section 9-220.3 of the Act that is in effect as of the
9 effective date of the performance-based rate tariff
10 approved by the Commission for that utility pursuant to
11 the provisions of this Section will be suspended by
12 operation of law as of the effective date of that
13 performance-based rate tariff. Notwithstanding anything in
14 paragraph (4) of subsection (a) and paragraph (2) of
15 subsection (e) of Section 9-220.3, a participating gas
16 utility shall not file a petition to initiate a final
17 reconciliation of amounts collected under such a surcharge
18 tariff on account of qualifying infrastructure investment
19 (as that term is defined in Section 9-220.3(b)) that
20 occurred during any calendar year for which a
21 reconciliation will be made under subsection (c), and no
22 adjustment to the participating gas utility's initial
23 rates as calculated under paragraph (1) of subsection (c)
24 shall be made based on the fact that the utility had such a
25 tariff in effect or recovered any portion of its revenue
26 requirement through such a tariff.

1 The participating gas utility shall file, together with
2 its tariff, final data based on its most recently filed ICC
3 Form 21, FERC Form 1, or FERC Form 2, as applicable, subject to
4 the adjustments specified in subsection (c), plus projected
5 plant additions and correspondingly updated depreciation
6 reserve and expense for the calendar year in which the tariff
7 and data are filed, that shall populate the performance-based
8 rate and set the initial gas delivery services rates under the
9 formula. For purposes of this Section, "ICC Form 21" means the
10 "Annual Report of Electric Utilities and/or Natural Gas
11 Utilities" or any successor to that report that natural gas
12 utilities are required to file with the Commission under
13 Section 5-109 of this Act. Nothing in this Section is intended
14 to allow costs that are not otherwise recoverable to be
15 recoverable by virtue of inclusion in ICC Form 21, FERC Form 1,
16 or FERC Form 2.

17 After the participating gas utility files its proposed
18 performance-based rate structure and protocols and initial
19 rates, the Commission shall initiate a docket to review the
20 filing. The Commission shall enter an order approving, or
21 approving as modified, the performance-based rate, including
22 the initial rates, as just and reasonable within 270 days
23 after the date on which the tariff was filed. Such review shall
24 be based on the same evidentiary standards, including, but not
25 limited to, those concerning the prudence and reasonableness
26 of the costs incurred by the utility, the Commission applies

1 in a hearing to review a filing for a general increase in rates
2 under Article IX of this Act. The initial rates shall take
3 effect within 30 days after the Commission's order approving
4 the performance-based rate tariff.

5 Until the Commission approves a different rate design and
6 cost allocation pursuant to subsection (f) of this Section,
7 rate design and cost allocation across customer classes shall
8 be consistent with the Commission's most recent order
9 regarding the participating gas utility's request for a
10 general increase in its delivery services rates.

11 Subsequent changes to the performance-based rate structure
12 or protocols shall be made as set forth in Section 9-201 of
13 this Act, but nothing in this subsection (c) is intended to
14 limit the Commission's authority under Article IX and other
15 provisions of this Act to initiate an investigation of a
16 participating gas utility's performance-based rate tariff,
17 provided that any such changes shall be consistent with
18 paragraphs (1) through (7) of this subsection (c). Any change
19 ordered by the Commission shall be made at the same time new
20 rates take effect following the Commission's next order
21 pursuant to subsection (e) of this Section, provided that the
22 new rates take effect no less than 30 days after the date on
23 which the Commission issues an order adopting the change.

24 In the event the performance-based rate is terminated, the
25 then current rates shall remain in effect until such time as
26 new rates are set pursuant to Article IX of this Act, subject

1 to retroactive rate adjustment, with interest, to reconcile
2 rates charged with actual costs.

3 (d) Beginning in the first calendar year following the
4 year in which this reporting requirement becomes effective, a
5 participating gas utility shall, within 45 days after the
6 close of each of the participating gas utility's fiscal
7 quarters, submit to the Commission a report that summarizes
8 the additions to utility plant that were placed into service
9 during the prior quarter, which for purposes of the report
10 shall be the most recently closed fiscal quarter, as well as
11 what utility plant the participating gas utility projects will
12 place into service through the end of the calendar year in
13 which the report is filed. The quarterly report provided will
14 be used for informational purposes only, and any estimates
15 therein shall not bind or limit the participating gas
16 utility's future decisions to invest in any utility plant or
17 other projects and may not be used in any Commission
18 proceeding to support any finding as to imprudence,
19 unreasonableness, or lack of use or usefulness of any
20 individual or aggregate level of utility plant or other
21 investment. Within 7 days of receiving a quarterly report, the
22 Commission shall make such report available to the public.
23 Each quarterly report shall include the following detail:

24 (1) the total dollar value of the additions to utility
25 plant placed in service during the prior quarter;

26 (2) a list of standing work orders for utility plant

1 placed in service during the prior quarter, including the
2 total dollar amount for the work reflected in each
3 standing work order as of the last day of the quarterly
4 reporting period, and a summary description of the
5 standing work order;

6 (3) a list of specific work orders for utility plant
7 placed in service during the prior quarter for utility
8 plant placed in service with a total dollar value as of the
9 last day of the quarterly reporting period that is equal
10 to or greater than \$500,000, inclusive of the dollar
11 amount reflected in each specific work order, and a
12 summary description of the specific work order;

13 (4) the estimated total dollar value of the additions
14 to utility plant projected to be placed in service through
15 the end of the calendar year in which the report is filed;

16 (5) a list of standing work orders for utility plant
17 projected to be placed in service through the end of the
18 calendar year in which the report is filed, including the
19 estimated dollar amount for the work reflected in each
20 standing work order, and a summary description of the
21 standing work order; and

22 (6) a list of specific work orders for utility plant
23 projected to be placed in service through the end of the
24 calendar year in which the report is filed with an
25 estimated dollar value that is equal to or greater than
26 \$500,000, inclusive of the estimated dollar amount for the

1 work reflected in each specific work order, and a summary
2 description of the specific work order.

3 (e) Subsequent to the Commission's issuance of an order
4 approving the participating gas utility's performance-based
5 rate structure and protocols, and initial rates under
6 subsection (c) of this Section, the utility shall file, on or
7 before May 1 of each year, with the Chief Clerk of the
8 Commission its updated cost inputs to the performance-based
9 rate for the applicable rate year and the corresponding new
10 charges. Each such filing shall conform to the following
11 requirements and include the following information:

12 (1) The inputs to the performance-based rate for the
13 applicable rate year shall be based on final historical
14 data reflected in the participating gas utility's most
15 recently filed annual ICC Form 21, or FERC Form 1, or FERC
16 Form 2, as applicable, subject to adjustments specified in
17 subsection (c) of this Section, plus projected plant
18 additions and correspondingly updated depreciation reserve
19 and expense for the calendar year in which the inputs are
20 filed. The filing shall also include a reconciliation of
21 the revenue requirement that was in effect for the prior
22 rate year (as set by the cost inputs for the prior rate
23 year) with the actual revenue requirement for the prior
24 rate year (determined using a year-end rate base) that
25 uses amounts reflected in the applicable ICC Form 21, FERC
26 Form 1, or FERC Form 2, that reports the actual costs for

1 the prior rate year. Any over-collection or
2 under-collection indicated by such reconciliation shall be
3 reflected as a credit against, or recovered as an
4 additional charge to, respectively, with interest
5 calculated at a rate equal to the participating gas
6 utility's weighted average cost of capital approved by the
7 Commission for the prior rate year, the charges for the
8 applicable rate year. Provided, however, that the first
9 such reconciliation shall be for the calendar year in
10 which the participating gas utility files its
11 performance-based rate tariff pursuant to subsection (c)
12 of this Section and shall reconcile (i) the revenue
13 requirement or revenue requirements established by the
14 rate order or rate orders in effect from time to time
15 during such calendar year (weighted, as applicable),
16 including any surcharge tariff authorized for the
17 participating gas utility pursuant to paragraph (3) of
18 subsection (a) of Section 9-220.3 of the Act with (ii) the
19 revenue requirement determined using a year-end rate base
20 for that calendar year calculated pursuant to the
21 performance-based rate using actual costs for that year as
22 reflected in the applicable ICC Form 21, FERC Form 1, or
23 FERC Form 2, as applicable, subject to adjustments
24 specified in subsection (c) of this Section. The first
25 such reconciliation is not intended to provide for the
26 recovery of costs previously excluded from rates based on

1 a prior Commission order finding of imprudence or
2 unreasonableness. Each reconciliation shall be certified
3 by the participating gas utility in the same manner that
4 ICC Form 21 is certified. The filing shall also include
5 the charge or credit, if any, resulting from the
6 calculation required by paragraph (6) of subsection (c) of
7 this Section.

8 Notwithstanding anything that may be to the contrary,
9 the intent of the reconciliations is to ultimately
10 reconcile the revenue requirement reflected in rates for
11 such calendar year, beginning with the calendar year in
12 which the participating gas utility files its
13 performance-based rate tariff pursuant to subsection (c)
14 of this Section, with what the revenue requirement
15 determined using a year-end rate base for the applicable
16 calendar year would have been had actual cost information
17 for the applicable calendar year been available at the
18 filing date.

19 (2) The new charges shall take effect beginning on the
20 first billing day of the following January billing period
21 and remain in effect through the last billing day of the
22 next December billing period regardless of whether the
23 Commission enters upon a hearing pursuant to this
24 subsection (e).

25 (3) The filing shall include relevant and necessary
26 data and documentation for the applicable rate year that

1 is consistent with the Commission's rules applicable to a
2 filing for a general increase in rates or any rules
3 adopted by the Commission to implement this Section.
4 Normalization adjustments shall not be required.
5 Notwithstanding any other provision of this Section or Act
6 or any rule or other requirement adopted by the
7 Commission, a participating gas utility with more than one
8 rate zone shall not be required to file a separate set of
9 such data and documentation for each rate zone and may
10 combine such data and documentation into a single set of
11 schedules.

12 Within 45 days after the participating gas utility files
13 its annual update of cost inputs to the performance-based
14 rate, the Commission shall have the authority, either upon
15 complaint or its own initiative, but with reasonable notice,
16 to enter upon a hearing concerning the prudence and
17 reasonableness of the costs incurred by the participating gas
18 utility to be recovered during the applicable rate year that
19 are reflected in the inputs to the performance-based rate
20 derived from the participating gas utility's ICC Form 21, FERC
21 Form 1, or FERC Form 2. During the course of the hearing, each
22 objection shall be stated with particularity and evidence
23 provided in support thereof, after which the utility shall
24 have the opportunity to rebut the evidence. Discovery shall be
25 allowed consistent with the Commission's Rules of Practice,
26 which Rules shall be enforced by the Commission or the

1 assigned administrative law judge. The Commission shall apply
2 the same evidentiary standards, including, but not limited to,
3 those concerning the prudence and reasonableness of the costs
4 incurred by the participating gas utility, in the hearing as
5 it would apply in a hearing to review a filing for a general
6 increase in rates under Article IX of this Act. The Commission
7 shall not, however, have the authority in a proceeding under
8 this subsection (e) to consider or order any changes to the
9 structure or protocols of the performance-based rate approved
10 pursuant to subsection (c) of this Section. In a proceeding
11 under this subsection (e), the Commission shall enter its
12 order no later than the earlier of 240 days after the utility's
13 filing of its annual update of cost inputs to the
14 performance-based rate or December 31. The Commission's
15 determinations of the prudence and reasonableness of the costs
16 incurred for the applicable calendar year shall be final upon
17 entry of the Commission's order and shall not be subject to
18 reopening, reexamination, or collateral attack in any other
19 Commission proceeding, case, docket, order, rule, or
20 regulation, provided, however, that nothing in this subsection
21 (e) shall prohibit a party from petitioning the Commission to
22 rehear or appeal to the courts the order pursuant to the
23 provisions of this Act.

24 In the event the Commission does not, either upon
25 complaint or its own initiative, enter upon a hearing within
26 45 days after the participating gas utility files the annual

1 update of cost inputs to its performance-based rate, then the
2 costs incurred for the applicable calendar year shall be
3 deemed prudent and reasonable, and the filed charges shall not
4 be subject to reopening, reexamination, or collateral attack
5 in any other proceeding, case, docket, order, rule, or
6 regulation.

7 A participating gas utility's first filing of the updated
8 cost inputs, and any Commission investigation of such inputs
9 pursuant to this subsection (e) shall proceed notwithstanding
10 the fact that the Commission's investigation under subsection
11 (c) of this Section is still pending and notwithstanding any
12 other law, order, rule, or Commission practice to the
13 contrary.

14 (f) Nothing in subsections (c) or (e) of this Section
15 shall prohibit the Commission from investigating, or a
16 participating gas utility from filing, revenue-neutral tariff
17 changes related to rate design of a performance-based rate
18 that has been placed into effect for the utility. Following
19 approval of a participating gas utility's performance-based
20 rate tariff pursuant to subsection (c) of this Section, the
21 utility shall make a filing with the Commission within one
22 year after the effective date of the performance-based rate
23 tariff that proposes changes to the tariff to incorporate the
24 findings of any final rate design orders of the Commission
25 applicable to the participating gas utility and entered
26 subsequent to the Commission's approval of the tariff. The

1 Commission shall, after notice and hearing, enter its order
2 approving, or approving with modification, the proposed
3 changes to the performance-based rate tariff within 240 days
4 after the utility's filing. Following such approval, the
5 utility shall make a filing with the Commission during each
6 subsequent 3-year period that either proposes revenue-neutral
7 tariff changes or re-files the existing tariffs without
8 change, which shall present the Commission with an opportunity
9 to suspend the tariffs and consider revenue-neutral tariff
10 changes related to rate design.

11 (g) Within 30 days after the filing of a tariff pursuant to
12 subsection (c) of this Section, each participating gas utility
13 shall develop and file with the Commission multi-year metrics.
14 For each participating gas utility, the following metrics
15 shall be designed to achieve, ratably (in equal annual
16 segments, unless otherwise specified) over a 10-year period,
17 improvement over baseline performance values as follows:

18 (1) System Integrity, Reliability, and Pipeline Safety
19 Improvement (under 49 CFR Part 192): Reduce the number of
20 outstanding, underground gas leaks on a participating gas
21 utility's gas system by 50% resulting in reduced methane
22 emissions into the environment, using a baseline of year
23 end 2020.

24 (2) System Integrity, Reliability, and Pipeline Safety
25 Improvement (under 49 CFR Part 192): Reduce the number of
26 outstanding above-ground gas leaks on a participating gas

1 utility's gas system by 50% resulting in reduced methane
2 emissions into the environment, using a baseline of year
3 end 2020.

4 (3) System Integrity, Reliability and Pipeline Safety
5 Improvement: Reduce the known quantity of gas transmission
6 pipeline facilities (including mains and associated
7 facilities) that do not have complete records to support
8 the maximum allowable operating pressures in accordance
9 with Federal Department of Transportation pipeline safety
10 regulations by 50% using a baseline of year end 2020.

11 (4) System Integrity, Reliability, and Pipeline Safety
12 Improvement: Reduce the known quantity of mechanically
13 coupled steel gas distribution pipeline facilities
14 (including mains, services, and associated facilities)
15 that are prone to leakage by 70% using a baseline of year
16 end 2020.

17 (5) Opportunities for minority-owned, woman-owned, and
18 veteran-owned business enterprises: design a performance
19 metric regarding the creation of opportunities for
20 minority-owned, woman-owned and veteran-owned business
21 enterprises consistent with State and federal law using a
22 base performance value of the percentage of the
23 participating gas utility's capital expenditures that were
24 paid to minority-owned, woman-owned and veteran-owned
25 business enterprises in the years 2018, 2019 and 2020.

26 The metrics shall include incremental performance goals

1 for each year of the 10-year period, which shall be designed to
2 demonstrate that the participating gas utility is on track to
3 achieve the performance goal in each category at the end of the
4 10-year period. The participating gas utility shall elect when
5 the 10-year period shall commence for the metrics set forth in
6 this subsection (g), provided that it begins no later than 14
7 months following the date on which the participating gas
8 utility files a tariff pursuant to subsection (c).

9 (h) The financial adjustments applicable to the metrics
10 described in subparagraphs (1) through (4) of subsection (g),
11 as applicable, shall be applied through an adjustment to the
12 participating gas utility's return on equity of no more than a
13 total of 40 basis points in any year, as follows:

14 (1) With respect to the incremental annual performance
15 goal established pursuant to subparagraph (1) of
16 subsection (g), for each year that a participating gas
17 utility does not achieve at least 95% of such goal, the
18 participating gas utility's return on equity shall be
19 reduced by 10 basis points; and for each year in which the
20 participating utility achieves 105% or more of such goal,
21 the participating gas utility's return on equity shall be
22 increased by 10 basis points.

23 (2) With respect to the incremental annual performance
24 goal established pursuant to subparagraph (2) of
25 subsection (g), for each year that a participating gas
26 utility does not achieve at least 95% of such goal, the

1 participating gas utility's return on equity shall be
2 reduced by 10 basis points; and for each year that a
3 participating gas utility achieves 105% or more of such
4 goal, the participating gas utility's return on equity
5 shall be increased by 10 basis points.

6 (3) With respect to the incremental annual performance
7 goal established pursuant to subparagraph (3) of
8 subsection (g), for each year that a participating gas
9 utility does not achieve at least 95% of such goal, the
10 participating gas utility's return on equity shall be
11 reduced by 10 basis points; and for each year that a
12 participating gas utility achieves 105% or more of such
13 goal, the participating gas utility's return on equity
14 shall be increased by 10 basis points.

15 (4) With respect to the incremental annual performance
16 goals established pursuant to subparagraph (4) of
17 subsection (g), for each year that a participating gas
18 utility does not achieve at least 95% of such goal, the
19 participating gas utility's return on equity shall be
20 reduced by 10 basis points; and for each year that a
21 participating gas utility achieves 105% or more of such
22 goal, the participating gas utility's return on equity
23 shall be increased by 10 basis points.

24 (i) The financial adjustments shall be applied as
25 described in subsection (h), as applicable, for the 12-month
26 period in which they accrued through a separate tariff

1 mechanism, which shall be filed by the participating gas
2 utility together with its metrics. In the event the
3 performance-based formula rate tariff established pursuant to
4 subsection (c) of this Section terminates, the participating
5 gas utility's obligations under subsection (g), as applicable,
6 and subsection (h), as applicable, of this Section and this
7 subsection (i) shall also terminate; provided, however, that
8 the tariff mechanism established pursuant to subsection (g) of
9 this Section and subsection (h), as applicable, and this
10 subsection (i) shall remain in effect until the remaining
11 balance of any financial adjustments at the time of such
12 termination is fully amortized.

13 The Commission shall, after notice and hearing, enter an
14 order within 120 days after the metrics are filed approving,
15 or approving with modification, a participating gas utility's
16 tariff or mechanism to satisfy the metrics set forth in
17 subsection (g), as applicable, of this Section and subsection
18 (h), as applicable, of this Section. On June 1 of each
19 subsequent year, each participating gas utility shall file a
20 report with the Commission that includes, among other things,
21 a description of how the participating gas utility performed
22 under each metric and an identification of any extraordinary
23 events that adversely impacted the participating gas utility's
24 performance. Whenever a participating gas utility's report on
25 its performance shows that a financial adjustment is warranted
26 under subsection (h) of this Section, the Commission shall,

1 after notice and hearing, enter an order approving any
2 financial adjustments in accordance with subsection (h) of
3 this Section. The Commission-approved financial adjustments
4 shall be applied beginning with the next rate year.

5 (j) This Section, other than this subsection (j), is
6 inoperative after December 31, 2032, for every participating
7 gas utility, after which time a participating gas utility
8 shall no longer be eligible to annually update the
9 performance-based rate tariff pursuant to subsection (e) of
10 this Section. At such time, the then current rates shall
11 remain in effect until such time as new rates are set pursuant
12 to Article IX of this Act, subject to retroactive adjustment,
13 with interest, to reconcile rates charged with actual costs.

14 The fact that this Section becomes inoperative as set
15 forth in this subsection shall not be construed to mean that
16 the Commission may reexamine or otherwise reopen prudence or
17 reasonableness determinations already made.

18 (220 ILCS 5/16-102)

19 Sec. 16-102. Definitions. For the purposes of this Article
20 the following terms shall be defined as set forth in this
21 Section.

22 "Alternative retail electric supplier" means every person,
23 cooperative, corporation, municipal corporation, company,
24 association, joint stock company or association, firm,
25 partnership, individual, or other entity, their lessees,

1 trustees, or receivers appointed by any court whatsoever, that
2 offers electric power or energy for sale, lease or in exchange
3 for other value received to one or more retail customers, or
4 that engages in the delivery or furnishing of electric power
5 or energy to such retail customers, and shall include, without
6 limitation, resellers, aggregators and power marketers, but
7 shall not include (i) electric utilities (or any agent of the
8 electric utility to the extent the electric utility provides
9 tariffed services to retail customers through that agent),
10 (ii) any electric cooperative or municipal system as defined
11 in Section 17-100 to the extent that the electric cooperative
12 or municipal system is serving retail customers within any
13 area in which it is or would be entitled to provide service
14 under the law in effect immediately prior to the effective
15 date of this amendatory Act of 1997, (iii) a public utility
16 that is owned and operated by any public institution of higher
17 education of this State, or a public utility that is owned by
18 such public institution of higher education and operated by
19 any of its lessees or operating agents, within any area in
20 which it is or would be entitled to provide service under the
21 law in effect immediately prior to the effective date of this
22 amendatory Act of 1997, (iv) a retail customer to the extent
23 that customer obtains its electric power and energy from that
24 customer's own cogeneration or self-generation facilities, (v)
25 an entity that owns, operates, sells, or arranges for the
26 installation of a customer's own cogeneration or

1 self-generation facilities, but only to the extent the entity
2 is engaged in owning, selling or arranging for the
3 installation of such facility, or operating the facility on
4 behalf of such customer, provided however that any such third
5 party owner or operator of a facility built after January 1,
6 1999, complies with the labor provisions of Section 16-128(a)
7 as though such third party were an alternative retail electric
8 supplier, or (vi) an industrial or manufacturing customer that
9 owns its own distribution facilities, to the extent that the
10 customer provides service from that distribution system to a
11 third-party contractor located on the customer's premises that
12 is integrally and predominantly engaged in the customer's
13 industrial or manufacturing process; provided, that if the
14 industrial or manufacturing customer has elected delivery
15 services, the customer shall pay transition charges applicable
16 to the electric power and energy consumed by the third-party
17 contractor unless such charges are otherwise paid by the third
18 party contractor, which shall be calculated based on the usage
19 of, and the base rates or the contract rates applicable to, the
20 third-party contractor in accordance with Section 16-102.

21 An entity that furnishes the service of charging electric
22 vehicles does not and shall not be deemed to sell electricity
23 and is not and shall not be deemed an alternative retail
24 electric supplier, and is not subject to regulation as such
25 under this Act notwithstanding the basis on which the service
26 is provided or billed. If, however, the entity is otherwise

1 deemed an alternative retail electric supplier under this Act,
2 or is otherwise subject to regulation under this Act, then
3 that entity is not exempt from and remains subject to the
4 otherwise applicable provisions of this Act. The installation,
5 maintenance, and repair of an electric vehicle charging
6 station shall comply with the requirements of subsection (a)
7 of Section 16-128 and Section 16-128A of this Act.

8 ~~For purposes of this Section, the term "electric vehicles"~~
9 ~~has the meaning ascribed to that term in Section 10 of the~~
10 ~~Electric Vehicle Act.~~

11 "Base rates" means the rates for those tariffed services
12 that the electric utility is required to offer pursuant to
13 subsection (a) of Section 16-103 and that were identified in a
14 rate order for collection of the electric utility's base rate
15 revenue requirement, excluding (i) separate automatic rate
16 adjustment riders then in effect, (ii) special or negotiated
17 contract rates, (iii) delivery services tariffs filed pursuant
18 to Section 16-108, (iv) real-time pricing, or (v) tariffs that
19 were in effect prior to October 1, 1996 and that based charges
20 for services on an index or average of other utilities'
21 charges, but including (vi) any subsequent redesign of such
22 rates for tariffed services that is authorized by the
23 Commission after notice and hearing.

24 "Competitive service" includes (i) any service that has
25 been declared to be competitive pursuant to Section 16-113 of
26 this Act, (ii) contract service, and (iii) services, other

1 than tariffed services, that are related to, but not necessary
2 for, the provision of electric power and energy or delivery
3 services.

4 "Contract service" means (1) services, including the
5 provision of electric power and energy or other services, that
6 are provided by mutual agreement between an electric utility
7 and a retail customer that is located in the electric
8 utility's service area, provided that, delivery services shall
9 not be a contract service until such services are declared
10 competitive pursuant to Section 16-113; and also means (2) the
11 provision of electric power and energy by an electric utility
12 to retail customers outside the electric utility's service
13 area pursuant to Section 16-116. Provided, however, contract
14 service does not include electric utility services provided
15 pursuant to (i) contracts that retail customers are required
16 to execute as a condition of receiving tariffed services, or
17 (ii) special or negotiated rate contracts for electric utility
18 services that were entered into between an electric utility
19 and a retail customer prior to the effective date of this
20 amendatory Act of 1997 and filed with the Commission.

21 "Delivery services" means those services provided by the
22 electric utility that are necessary in order for the
23 transmission and distribution systems to function so that
24 retail customers located in the electric utility's service
25 area can receive electric power and energy from suppliers
26 other than the electric utility, and shall include, without

1 limitation, standard metering and billing services.

2 "Electric utility" means a public utility, as defined in
3 Section 3-105 of this Act, that has a franchise, license,
4 permit or right to furnish or sell electricity to retail
5 customers within a service area.

6 "Electric vehicle" means: (i) a battery-powered vehicle
7 operated solely by electricity that can be recharged from an
8 external source; or (ii) a plug-in hybrid electric vehicle
9 that operates on electricity and another fuel and has a
10 battery that can be recharged from an external source.

11 "Electric vehicle charging station" means any facility,
12 infrastructure, or equipment that is used to charge a battery
13 or other energy storage device of an electric vehicle.

14 "Energy storage" or "storage" means any infrastructure,
15 facility, technology, or device used to store energy for use
16 on an electric distribution or transmission system and shall
17 not include or be considered energy generation.

18 "Mandatory transition period" means the period from the
19 effective date of this amendatory Act of 1997 through January
20 1, 2007.

21 "Municipal system" shall have the meaning set forth in
22 Section 17-100.

23 "Real-time pricing" means tariffed retail charges for
24 delivered electric power and energy that vary hour-to-hour and
25 are determined from wholesale market prices using a
26 methodology approved by the Illinois Commerce Commission.

1 "Retail customer" means a single entity using electric
2 power or energy at a single premises and that (A) either (i) is
3 receiving or is eligible to receive tariffed services from an
4 electric utility, or (ii) that is served by a municipal system
5 or electric cooperative within any area in which the municipal
6 system or electric cooperative is or would be entitled to
7 provide service under the law in effect immediately prior to
8 the effective date of this amendatory Act of 1997, or (B) an
9 entity which on the effective date of this Act was receiving
10 electric service from a public utility and (i) was engaged in
11 the practice of resale and redistribution of such electricity
12 within a building prior to January 2, 1957, or (ii) was
13 providing lighting services to tenants in a multi-occupancy
14 building, but only to the extent such resale, redistribution
15 or lighting service is authorized by the electric utility's
16 tariffs that were on file with the Commission on the effective
17 date of this Act.

18 "Service area" means (i) the geographic area within which
19 an electric utility was lawfully entitled to provide electric
20 power and energy to retail customers as of the effective date
21 of this amendatory Act of 1997, and includes (ii) the location
22 of any retail customer to which the electric utility was
23 lawfully providing electric utility services on such effective
24 date.

25 "Small commercial retail customer" means those
26 nonresidential retail customers of an electric utility

1 consuming 15,000 kilowatt-hours or less of electricity
2 annually in its service area.

3 "Tariffed service" means services provided to retail
4 customers by an electric utility as defined by its rates on
5 file with the Commission pursuant to the provisions of Article
6 IX of this Act, but shall not include competitive services.

7 "Transition charge" means a charge expressed in cents per
8 kilowatt-hour that is calculated for a customer or class of
9 customers as follows for each year in which an electric
10 utility is entitled to recover transition charges as provided
11 in Section 16-108:

12 (1) the amount of revenue that an electric utility
13 would receive from the retail customer or customers if it
14 were serving such customers' electric power and energy
15 requirements as a tariffed service based on (A) all of the
16 customers' actual usage during the 3 years ending 90 days
17 prior to the date on which such customers were first
18 eligible for delivery services pursuant to Section 16-104,
19 and (B) on (i) the base rates in effect on October 1, 1996
20 (adjusted for the reductions required by subsection (b) of
21 Section 16-111, for any reduction resulting from a rate
22 decrease under Section 16-101(b), for any restatement of
23 base rates made in conjunction with an elimination of the
24 fuel adjustment clause pursuant to subsection (b), (d), or
25 (f) of Section 9-220 and for any removal of
26 decommissioning costs from base rates pursuant to Section

1 16-114) and any separate automatic rate adjustment riders
2 (other than a decommissioning rate as defined in Section
3 16-114) under which the customers were receiving or, had
4 they been customers, would have received electric power
5 and energy from the electric utility during the year
6 immediately preceding the date on which such customers
7 were first eligible for delivery service pursuant to
8 Section 16-104, or (ii) to the extent applicable, any
9 contract rates, including contracts or rates for
10 consolidated or aggregated billing, under which such
11 customers were receiving electric power and energy from
12 the electric utility during such year;

13 (2) less the amount of revenue, other than revenue
14 from transition charges and decommissioning rates, that
15 the electric utility would receive from such retail
16 customers for delivery services provided by the electric
17 utility, assuming such customers were taking delivery
18 services for all of their usage, based on the delivery
19 services tariffs in effect during the year for which the
20 transition charge is being calculated and on the usage
21 identified in paragraph (1);

22 (3) less the market value for the electric power and
23 energy that the electric utility would have used to supply
24 all of such customers' electric power and energy
25 requirements, as a tariffed service, based on the usage
26 identified in paragraph (1), with such market value

1 determined in accordance with Section 16-112 of this Act;

2 (4) less the following amount which represents the
3 amount to be attributed to new revenue sources and cost
4 reductions by the electric utility through the end of the
5 period for which transition costs are recovered pursuant
6 to Section 16-108, referred to in this Article XVI as a
7 "mitigation factor":

8 (A) for nonresidential retail customers, an amount
9 equal to the greater of (i) 0.5 cents per
10 kilowatt-hour during the period October 1, 1999
11 through December 31, 2004, 0.6 cents per kilowatt-hour
12 in calendar year 2005, and 0.9 cents per kilowatt-hour
13 in calendar year 2006, multiplied in each year by the
14 usage identified in paragraph (1), or (ii) an amount
15 equal to the following percentages of the amount
16 produced by applying the applicable base rates
17 (adjusted as described in subparagraph (1)(B)) or
18 contract rate to the usage identified in paragraph
19 (1): 8% for the period October 1, 1999 through
20 December 31, 2002, 10% in calendar years 2003 and
21 2004, 11% in calendar year 2005 and 12% in calendar
22 year 2006; and

23 (B) for residential retail customers, an amount
24 equal to the following percentages of the amount
25 produced by applying the base rates in effect on
26 October 1, 1996 (adjusted as described in subparagraph

1 (1)(B)) to the usage identified in paragraph (1): (i)
2 6% from May 1, 2002 through December 31, 2002, (ii) 7%
3 in calendar years 2003 and 2004, (iii) 8% in calendar
4 year 2005, and (iv) 10% in calendar year 2006;

5 (5) divided by the usage of such customers identified
6 in paragraph (1),

7 provided that the transition charge shall never be less than
8 zero.

9 "Unbundled service" means a component or constituent part
10 of a tariffed service which the electric utility subsequently
11 offers separately to its customers.

12 (Source: P.A. 97-1128, eff. 8-28-12.)

13 (220 ILCS 5/16-107.6)

14 Sec. 16-107.6. Distributed generation rebate.

15 (a) In this Section:

16 "Smart inverter" means a device that converts direct
17 current into alternating current and can autonomously
18 contribute to grid support during excursions from normal
19 operating voltage and frequency conditions by providing each
20 of the following: dynamic reactive and real power support,
21 voltage and frequency ride-through, ramp rate controls,
22 communication systems with ability to accept external
23 commands, and other functions from the electric utility.

24 "Subscriber" has the meaning set forth in Section 1-10 of
25 the Illinois Power Agency Act.

1 "Subscription" has the meaning set forth in Section 1-10
2 of the Illinois Power Agency Act.

3 "Threshold date" means the date on which the load of an
4 electricity provider's net metering customers equals 5% of the
5 total peak demand supplied by that electricity provider during
6 the previous year, as specified under subsection (j) of
7 Section 16-107.5 of this Act.

8 (b) An electric utility that serves more than 200,000
9 customers in the State shall file a petition with the
10 Commission requesting approval of the utility's tariff to
11 provide a rebate to a retail customer who owns or operates
12 distributed generation that meets the following criteria:

13 (1) has a nameplate generating capacity no greater
14 than 2,000 kilowatts and is primarily used to offset that
15 customer's electricity load;

16 (2) is located on the customer's premises, for the
17 customer's own use, and not for commercial use or sales,
18 including, but not limited to, wholesale sales of electric
19 power and energy;

20 (3) is located in the electric utility's service
21 territory; and

22 (4) is interconnected under rules adopted by the
23 Commission by means of the inverter or smart inverter
24 required by this Section, as applicable.

25 For purposes of this Section, "distributed generation"
26 shall satisfy the definition of distributed renewable energy

1 generation device set forth in Section 1-10 of the Illinois
2 Power Agency Act to the extent such definition is consistent
3 with the requirements of this Section.

4 In addition, any new photovoltaic distributed generation
5 that is installed after the effective date of this amendatory
6 Act of the 99th General Assembly must be installed by a
7 qualified person, as defined by subsection (i) of Section 1-56
8 of the Illinois Power Agency Act.

9 The tariff shall provide that the utility shall be
10 permitted to operate and control the smart inverter associated
11 with the distributed generation that is the subject of the
12 rebate for the purpose of preserving reliability during
13 distribution system reliability events and shall address the
14 terms and conditions of the operation and the compensation
15 associated with the operation. Nothing in this Section shall
16 negate or supersede Institute of Electrical and Electronics
17 Engineers interconnection requirements or standards or other
18 similar standards or requirements. The tariff shall also
19 provide for additional uses of the smart inverter that shall
20 be separately compensated and which may include, but are not
21 limited to, voltage and VAR support, regulation, and other
22 grid services. As part of the proceeding described in
23 subsection (e) of this Section, the Commission shall review
24 and determine whether smart inverters can provide any
25 additional uses or services. If the Commission determines that
26 an additional use or service would be beneficial, the

1 Commission shall determine the terms and conditions of the
2 operation and how the use or service should be separately
3 compensated.

4 (c) The proposed tariff authorized by subsection (b) of
5 this Section shall include the following participation terms
6 and formulae to calculate the value of the rebates to be
7 applied under this Section for distributed generation that
8 satisfies the criteria set forth in subsection (b) of this
9 Section:

10 (1) Until the utility files its tariff or tariffs to
11 place into effect the rebate values established by the
12 Commission under subsection (e) of this Section,
13 non-residential customers that are taking service under a
14 net metering program offered by an electricity provider
15 under the terms of Section 16-107.5 of this Act may apply
16 for a rebate as provided for in this Section. The value of
17 the rebate shall be \$250 per kilowatt of nameplate
18 generating capacity, measured as nominal DC power output,
19 of a non-residential customer's distributed generation.

20 (2) After the utility's tariff or tariffs setting the
21 new rebate values established under subsection (d) of this
22 Section take effect, retail customers may, as applicable,
23 make the following elections:

24 (A) Residential customers that are taking service
25 under a net metering program offered by an electricity
26 provider under the terms of Section 16-107.5 of this

1 Act on the threshold date may elect to either continue
2 to take such service under the terms of such program as
3 in effect on such threshold date for the useful life of
4 the customer's eligible renewable electric generating
5 facility as defined in such Section, or file an
6 application to receive a rebate under the terms of
7 this Section, provided that such application must be
8 submitted within 6 months after the effective date of
9 the tariff approved under subsection (d) of this
10 Section. The value of the rebate shall be the amount
11 established by the Commission and reflected in the
12 utility's tariff pursuant to subsection (e) of this
13 Section.

14 (B) Non-residential customers that are taking
15 service under a net metering program offered by an
16 electricity provider under the terms of Section
17 16-107.5 of this Act on the threshold date may apply
18 for a rebate as provided for in this Section. The value
19 of the rebate shall be the amount established by the
20 Commission and reflected in the utility's tariff
21 pursuant to subsection (e) of this Section.

22 (3) Upon approval of a rebate application submitted
23 under this subsection (c), the retail customer shall no
24 longer be entitled to receive any delivery service credits
25 for the excess electricity generated by its facility and
26 shall be subject to the provisions of subsection (n) of

1 Section 16-107.5 of this Act.

2 (4) To be eligible for a rebate described in this
3 subsection (c), customers who begin taking service after
4 the effective date of this amendatory Act of the 99th
5 General Assembly under a net metering program offered by
6 an electricity provider under the terms of Section
7 16-107.5 of this Act must have a smart inverter associated
8 with the customer's distributed generation.

9 (d) The Commission shall review the proposed tariff
10 submitted under subsections (b) and (c) of this Section and
11 may make changes to the tariff that are consistent with this
12 Section and with the Commission's authority under Article IX
13 of this Act, subject to notice and hearing. Following notice
14 and hearing, the Commission shall issue an order approving, or
15 approving with modification, such tariff no later than 240
16 days after the utility files its tariff.

17 (e) When the total generating capacity of the electricity
18 provider's net metering customers is equal to 3%, the
19 Commission shall open an investigation into an annual process
20 and formula for calculating the value of rebates for the
21 retail customers described in subsections (b) and (f) of this
22 Section that submit rebate applications after the threshold
23 date for an electric utility that elected to file a tariff
24 pursuant to this Section. The investigation shall include
25 diverse sets of stakeholders, calculations for valuing
26 distributed energy resource benefits to the grid based on best

1 practices, and assessments of present and future technological
2 capabilities of distributed energy resources. The value of
3 such rebates shall reflect the value of the distributed
4 generation to the distribution system at the location at which
5 it is interconnected, taking into account the geographic,
6 time-based, and performance-based benefits, as well as
7 technological capabilities and present and future grid needs.
8 No later than 10 days after the Commission enters its final
9 order under this subsection (e), the utility shall file its
10 tariff or tariffs in compliance with the order, and the
11 Commission shall approve, or approve with modification, the
12 tariff or tariffs within 45 days after the utility's filing.
13 For those rebate applications filed after the threshold date
14 but before the utility's tariff or tariffs filed pursuant to
15 this subsection (e) take effect, the value of the rebate shall
16 remain at the value established in subsection (c) of this
17 Section until the tariff is approved.

18 (f) Notwithstanding any provision of this Act to the
19 contrary, the owner, developer, or subscriber of a generation
20 facility that is part of a net metering program provided under
21 subsection (1) of Section 16-107.5 shall also be eligible to
22 apply for the rebate described in this Section. A subscriber
23 to the generation facility may apply for a rebate in the amount
24 of the subscriber's subscription only if the owner, developer,
25 or previous subscriber to the same panel or panels has not
26 already submitted an application, and, regardless of whether

1 the subscriber is a residential or non-residential customer,
2 may be allowed the amount identified in paragraph (1) of
3 subsection (c) or in subsection (e) of this Section applicable
4 to such customer on the date that the application is
5 submitted. An application for a rebate for a portion of a
6 project described in this subsection (f) may be submitted at
7 or after the time that a related request for net metering is
8 made.

9 (g) No later than 60 days after the utility receives an
10 application for a rebate under its tariff approved under
11 subsection (d) or (e) of this Section, the utility shall issue
12 a rebate to the applicant under the terms of the tariff. In the
13 event the application is incomplete or the utility is
14 otherwise unable to calculate the payment based on the
15 information provided by the owner, the utility shall issue the
16 payment no later than 60 days after the application is
17 complete or all requested information is received.

18 (h) An electric utility shall recover from its retail
19 customers all of the costs of the rebates made under a tariff
20 or tariffs placed into effect under this Section, including,
21 but not limited to, the value of the rebates and all costs
22 incurred by the utility to comply with and implement this
23 Section, consistent with the following provisions:

24 (1) The utility shall defer the full amount of its
25 costs incurred under this Section as a regulatory asset.

26 The total costs deferred as a regulatory asset shall be

1 amortized over a 15-year period. The unamortized balance
2 shall be recognized as of December 31 for a given year. The
3 utility shall also earn a return on the total of the
4 unamortized balance of the regulatory assets, less any
5 deferred taxes related to the unamortized balance, at an
6 annual rate equal to the utility's weighted average cost
7 of capital that includes, based on a year-end capital
8 structure, the utility's actual cost of debt for the
9 applicable calendar year and a cost of equity, which in
10 all years for electric utilities that serve more than
11 3,000,000 retail customers in this State, and in each
12 calendar year commencing before January 1, 2021 for
13 electric utilities that serve less than 3,000,000 retail
14 customers but more than 500,000 retail customers in this
15 State, shall be calculated as the sum of (i) the average
16 for the applicable calendar year of the monthly average
17 yields of 30-year U.S. Treasury bonds published by the
18 Board of Governors of the Federal Reserve System in its
19 weekly H.15 Statistical Release or successor publication;
20 and (ii) 580 basis points, including a revenue conversion
21 factor calculated to recover or refund all additional
22 income taxes that may be payable or receivable as a result
23 of that return. For electric utilities that serve less
24 than 3,000,000 retail customers but more than 500,000
25 retail customers in this State, for each calendar year
26 commencing after December 31, 2020, the cost of equity

1 shall be equal to the national average cost of equity as
2 calculated under this paragraph (1). For purposes of this
3 paragraph (1), the national average cost of equity for an
4 applicable calendar year shall be the simple average of
5 the cost of equity specified and approved in each order of
6 a state regulatory commission, other than the Commission,
7 issued during such calendar year that is applicable to
8 base rates for retail electric service provided by an
9 investor-owned public utility company operating in the
10 United States. No order shall be excluded from the
11 national average cost of equity calculated under this
12 paragraph (1) on the grounds that it was arrived at by
13 stipulation or agreement or is subject to rehearing or
14 appeal. In its final order in the proceeding occurring
15 pursuant to this subsection (h) of this Section during
16 calendar year 2021, the Commission shall set the cost of
17 equity using the method applicable to calendar years
18 commencing prior to January 1, 2021. In its final orders
19 in the proceedings occurring pursuant to subsection (h) of
20 this Section in years subsequent to calendar year 2021,
21 including the reconciliation of the 2021 rate year, the
22 Commission shall set the cost of equity using the method
23 applicable to calendar years commencing after December 31,
24 2020. If, for any calendar year, there are fewer than 15
25 applicable orders of state regulatory commissions with
26 which to compute the average cost of equity, the

1 Commission shall include in the calculation of the
2 national average the number of state regulatory orders
3 from the year or years immediately preceding such calendar
4 year necessary to reach a total of 15, beginning with the
5 most recently issued and proceeding in reverse
6 chronological order.

7 When an electric utility creates a regulatory asset
8 under the provisions of this Section, the costs are
9 recovered over a period during which customers also
10 receive a benefit, which is in the public interest.
11 Accordingly, it is the intent of the General Assembly that
12 an electric utility that elects to create a regulatory
13 asset under the provisions of this Section shall recover
14 all of the associated costs, including, but not limited
15 to, its cost of capital as set forth in this Section. After
16 the Commission has approved the prudence and
17 reasonableness of the costs that comprise the regulatory
18 asset, the electric utility shall be permitted to recover
19 all such costs, and the value and recoverability through
20 rates of the associated regulatory asset shall not be
21 limited, altered, impaired, or reduced. To enable the
22 financing of the incremental capital expenditures,
23 including regulatory assets, for electric utilities that
24 serve less than 3,000,000 retail customers but more than
25 500,000 retail customers in the State, the utility's
26 actual year-end capital structure that includes a common

1 equity ratio, excluding goodwill, of up to and including
2 54% ~~50%~~ of the total capital structure shall be deemed
3 reasonable and used to set rates.

4 (2) The utility, at its election, may recover all of
5 the costs it incurs under this Section as part of a filing
6 for a general increase in rates under Article IX of this
7 Act, as part of an annual filing to update a
8 performance-based formula rate under subsection (d) of
9 Section 16-108.5 of this Act, or through an automatic
10 adjustment clause tariff, provided that nothing in this
11 paragraph (2) permits the double recovery of such costs
12 from customers. If the utility elects to recover the costs
13 it incurs under this Section through an automatic
14 adjustment clause tariff, the utility may file its
15 proposed tariff together with the tariff it files under
16 subsection (b) of this Section or at a later time. The
17 proposed tariff shall provide for an annual
18 reconciliation, less any deferred taxes related to the
19 reconciliation, with interest at an annual rate of return
20 equal to the utility's weighted average cost of capital as
21 calculated under paragraph (1) of this subsection (h),
22 including a revenue conversion factor calculated to
23 recover or refund all additional income taxes that may be
24 payable or receivable as a result of that return, of the
25 revenue requirement reflected in rates for each calendar
26 year, beginning with the calendar year in which the

1 utility files its automatic adjustment clause tariff under
2 this subsection (h), with what the revenue requirement
3 would have been had the actual cost information for the
4 applicable calendar year been available at the filing
5 date. The Commission shall review the proposed tariff and
6 may make changes to the tariff that are consistent with
7 this Section and with the Commission's authority under
8 Article IX of this Act, subject to notice and hearing.
9 Following notice and hearing, the Commission shall issue
10 an order approving, or approving with modification, such
11 tariff no later than 240 days after the utility files its
12 tariff.

13 (i) No later than 90 days after the Commission enters an
14 order, or order on rehearing, whichever is later, approving an
15 electric utility's proposed tariff under subsection (d) of
16 this Section, the electric utility shall provide notice of the
17 availability of rebates under this Section. Subsequent to the
18 utility's notice, any entity that offers in the State, for
19 sale or lease, distributed generation and estimates the dollar
20 saving attributable to such distributed generation shall
21 provide estimates based on both delivery service credits and
22 the rebates available under this Section.

23 (Source: P.A. 99-906, eff. 6-1-17.)

24 (220 ILCS 5/16-108.5)

25 Sec. 16-108.5. Infrastructure investment and

1 modernization; regulatory reform.

2 (a) (Blank).

3 (b) For purposes of this Section, "participating utility"
4 means an electric utility or a combination utility serving
5 more than 1,000,000 customers in Illinois that voluntarily
6 elects and commits to undertake (i) the infrastructure
7 investment program consisting of the commitments and
8 obligations described in this subsection (b) and (ii) the
9 customer assistance program consisting of the commitments and
10 obligations described in subsection (b-10) of this Section,
11 notwithstanding any other provisions of this Act and without
12 obtaining any approvals from the Commission or any other
13 agency other than as set forth in this Section, regardless of
14 whether any such approval would otherwise be required.
15 "Combination utility" means a utility that, as of January 1,
16 2011, provided electric service to at least one million retail
17 customers in Illinois and gas service to at least 500,000
18 retail customers in Illinois. A participating utility shall
19 recover the expenditures made under the infrastructure
20 investment program through the ratemaking process, including,
21 but not limited to, the performance-based formula rate and
22 process set forth in this Section.

23 During the infrastructure investment program's peak
24 program year, a participating utility other than a combination
25 utility shall create 2,000 full-time equivalent jobs in
26 Illinois, and a participating utility that is a combination

1 utility shall create 450 full-time equivalent jobs in Illinois
2 related to the provision of electric service. These jobs shall
3 include direct jobs, contractor positions, and induced jobs,
4 but shall not include any portion of a job commitment, not
5 specifically contingent on an amendatory Act of the 97th
6 General Assembly becoming law, between a participating utility
7 and a labor union that existed on December 30, 2011 (the
8 effective date of Public Act 97-646) and that has not yet been
9 fulfilled. A portion of the full-time equivalent jobs created
10 by each participating utility shall include incremental
11 personnel hired subsequent to December 30, 2011 (the effective
12 date of Public Act 97-646). For purposes of this Section,
13 "peak program year" means the consecutive 12-month period with
14 the highest number of full-time equivalent jobs that occurs
15 between the beginning of investment year 2 and the end of
16 investment year 4.

17 A participating utility shall meet one of the following
18 commitments, as applicable:

19 (1) Beginning no later than 180 days after a
20 participating utility other than a combination utility
21 files a performance-based formula rate tariff pursuant to
22 subsection (c) of this Section, or, beginning no later
23 than January 1, 2012 if such utility files such
24 performance-based formula rate tariff within 14 days of
25 October 26, 2011 (the effective date of Public Act
26 97-616), the participating utility shall, except as

1 provided in subsection (b-5):

2 (A) over a 5-year period, invest an estimated
3 \$1,300,000,000 in electric system upgrades,
4 modernization projects, and training facilities,
5 including, but not limited to:

6 (i) distribution infrastructure improvements
7 totaling an estimated \$1,000,000,000, including
8 underground residential distribution cable
9 injection and replacement and mainline cable
10 system refurbishment and replacement projects;

11 (ii) training facility construction or upgrade
12 projects totaling an estimated \$10,000,000,
13 provided that, at a minimum, one such facility
14 shall be located in a municipality having a
15 population of more than 2 million residents and
16 one such facility shall be located in a
17 municipality having a population of more than
18 150,000 residents but fewer than 170,000
19 residents; any such new facility located in a
20 municipality having a population of more than 2
21 million residents must be designed for the purpose
22 of obtaining, and the owner of the facility shall
23 apply for, certification under the United States
24 Green Building Council's Leadership in Energy
25 Efficiency Design Green Building Rating System;

26 (iii) wood pole inspection, treatment, and

1 replacement programs;

2 (iv) an estimated \$200,000,000 for reducing
3 the susceptibility of certain circuits to
4 storm-related damage, including, but not limited
5 to, high winds, thunderstorms, and ice storms;
6 improvements may include, but are not limited to,
7 overhead to underground conversion and other
8 engineered outcomes for circuits; the
9 participating utility shall prioritize the
10 selection of circuits based on each circuit's
11 historical susceptibility to storm-related damage
12 and the ability to provide the greatest customer
13 benefit upon completion of the improvements; to be
14 eligible for improvement, the participating
15 utility's ability to maintain proper tree
16 clearances surrounding the overhead circuit must
17 not have been impeded by third parties; and

18 (B) over a 10-year period, invest an estimated
19 \$1,300,000,000 to upgrade and modernize its
20 transmission and distribution infrastructure and in
21 Smart Grid electric system upgrades, including, but
22 not limited to:

23 (i) additional smart meters;

24 (ii) distribution automation;

25 (iii) associated cyber secure data
26 communication network; and

1 (iv) substation micro-processor relay
2 upgrades.

3 (2) Beginning no later than 180 days after a
4 participating utility that is a combination utility files
5 a performance-based formula rate tariff pursuant to
6 subsection (c) of this Section, or, beginning no later
7 than January 1, 2012 if such utility files such
8 performance-based formula rate tariff within 14 days of
9 October 26, 2011 (the effective date of Public Act
10 97-616), the participating utility shall, except as
11 provided in subsection (b-5):

12 (A) over a 10-year period, invest an estimated
13 \$265,000,000 in electric system upgrades,
14 modernization projects, and training facilities,
15 including, but not limited to:

16 (i) distribution infrastructure improvements
17 totaling an estimated \$245,000,000, which may
18 include bulk supply substations, transformers,
19 reconductoring, and rebuilding overhead
20 distribution and sub-transmission lines,
21 underground residential distribution cable
22 injection and replacement and mainline cable
23 system refurbishment and replacement projects;

24 (ii) training facility construction or upgrade
25 projects totaling an estimated \$1,000,000; any
26 such new facility must be designed for the purpose

1 of obtaining, and the owner of the facility shall
2 apply for, certification under the United States
3 Green Building Council's Leadership in Energy
4 Efficiency Design Green Building Rating System;
5 and

6 (iii) wood pole inspection, treatment, and
7 replacement programs; and

8 (B) over a 10-year period, invest an estimated
9 \$360,000,000 to upgrade and modernize its transmission
10 and distribution infrastructure and in Smart Grid
11 electric system upgrades, including, but not limited
12 to:

13 (i) additional smart meters;

14 (ii) distribution automation;

15 (iii) associated cyber secure data
16 communication network; and

17 (iv) substation micro-processor relay
18 upgrades.

19 For purposes of this Section, "Smart Grid electric system
20 upgrades" shall have the meaning set forth in subsection (a)
21 of Section 16-108.6 of this Act.

22 The investments in the infrastructure investment program
23 described in this subsection (b) shall be incremental to the
24 participating utility's annual capital investment program, as
25 defined by, for purposes of this subsection (b), the
26 participating utility's average capital spend for calendar

1 years 2008, 2009, and 2010 as reported in the applicable
2 Federal Energy Regulatory Commission (FERC) Form 1; provided
3 that where one or more utilities have merged, the average
4 capital spend shall be determined using the aggregate of the
5 merged utilities' capital spend reported in FERC Form 1 for
6 the years 2008, 2009, and 2010. A participating utility may
7 add reasonable construction ramp-up and ramp-down time to the
8 investment periods specified in this subsection (b). For each
9 such investment period, the ramp-up and ramp-down time shall
10 not exceed a total of 6 months.

11 Within 60 days after filing a tariff under subsection (c)
12 of this Section, a participating utility shall submit to the
13 Commission its plan, including scope, schedule, and staffing,
14 for satisfying its infrastructure investment program
15 commitments pursuant to this subsection (b). The submitted
16 plan shall include a schedule and staffing plan for the next
17 calendar year. The plan shall also include a plan for the
18 creation, operation, and administration of a Smart Grid test
19 bed as described in subsection (c) of Section 16-108.8. The
20 plan need not allocate the work equally over the respective
21 periods, but should allocate material increments throughout
22 such periods commensurate with the work to be undertaken. No
23 later than April 1 of each subsequent year, the utility shall
24 submit to the Commission a report that includes any updates to
25 the plan, a schedule for the next calendar year, the
26 expenditures made for the prior calendar year and

1 cumulatively, and the number of full-time equivalent jobs
2 created for the prior calendar year and cumulatively. If the
3 utility is materially deficient in satisfying a schedule or
4 staffing plan, then the report must also include a corrective
5 action plan to address the deficiency. The fact that the plan,
6 implementation of the plan, or a schedule changes shall not
7 imply the imprudence or unreasonableness of the infrastructure
8 investment program, plan, or schedule. Further, no later than
9 45 days following the last day of the first, second, and third
10 quarters of each year of the plan, a participating utility
11 shall submit to the Commission a verified quarterly report for
12 the prior quarter that includes (i) the total number of
13 full-time equivalent jobs created during the prior quarter,
14 (ii) the total number of employees as of the last day of the
15 prior quarter, (iii) the total number of full-time equivalent
16 hours in each job classification or job title, (iv) the total
17 number of incremental employees and contractors in support of
18 the investments undertaken pursuant to this subsection (b) for
19 the prior quarter, and (v) any other information that the
20 Commission may require by rule.

21 With respect to the participating utility's peak job
22 commitment, if, after considering the utility's corrective
23 action plan and compliance thereunder, the Commission enters
24 an order finding, after notice and hearing, that a
25 participating utility did not satisfy its peak job commitment
26 described in this subsection (b) for reasons that are

1 reasonably within its control, then the Commission shall also
2 determine, after consideration of the evidence, including, but
3 not limited to, evidence submitted by the Department of
4 Commerce and Economic Opportunity and the utility, the
5 deficiency in the number of full-time equivalent jobs during
6 the peak program year due to such failure. The Commission
7 shall notify the Department of any proceeding that is
8 initiated pursuant to this paragraph. For each full-time
9 equivalent job deficiency during the peak program year that
10 the Commission finds as set forth in this paragraph, the
11 participating utility shall, within 30 days after the entry of
12 the Commission's order, pay \$6,000 to a fund for training
13 grants administered under Section 605-800 of the Department of
14 Commerce and Economic Opportunity Law, which shall not be a
15 recoverable expense.

16 With respect to the participating utility's investment
17 amount commitments, if, after considering the utility's
18 corrective action plan and compliance thereunder, the
19 Commission enters an order finding, after notice and hearing,
20 that a participating utility is not satisfying its investment
21 amount commitments described in this subsection (b), then the
22 utility shall no longer be eligible to annually update the
23 performance-based formula rate tariff pursuant to subsection
24 (d) of this Section. In such event, the then current rates
25 shall remain in effect until such time as new rates are set
26 pursuant to Article IX of this Act, subject to retroactive

1 adjustment, with interest, to reconcile rates charged with
2 actual costs.

3 If the Commission finds that a participating utility is no
4 longer eligible to update the performance-based formula rate
5 tariff pursuant to subsection (d) of this Section, or the
6 performance-based formula rate is otherwise terminated, then
7 the participating utility's voluntary commitments and
8 obligations under this subsection (b) shall immediately
9 terminate, except for the utility's obligation to pay an
10 amount already owed to the fund for training grants pursuant
11 to a Commission order.

12 In meeting the obligations of this subsection (b), to the
13 extent feasible and consistent with State and federal law, the
14 investments under the infrastructure investment program should
15 provide employment opportunities for all segments of the
16 population and workforce, including minority-owned and
17 woman-owned ~~female-owned~~ business enterprises, and shall not,
18 consistent with State and federal law, discriminate based on
19 race or socioeconomic status.

20 (b-5) Nothing in this Section shall prohibit the
21 Commission from investigating the prudence and reasonableness
22 of the expenditures made under the infrastructure investment
23 program during the annual review required by subsection (d) of
24 this Section and shall, as part of such investigation,
25 determine whether the utility's actual costs under the program
26 are prudent and reasonable. The fact that a participating

1 utility invests more than the minimum amounts specified in
2 subsection (b) of this Section or its plan shall not imply
3 imprudence or unreasonableness.

4 If the participating utility finds that it is implementing
5 its plan for satisfying the infrastructure investment program
6 commitments described in subsection (b) of this Section at a
7 cost below the estimated amounts specified in subsection (b)
8 of this Section, then the utility may file a petition with the
9 Commission requesting that it be permitted to satisfy its
10 commitments by spending less than the estimated amounts
11 specified in subsection (b) of this Section. The Commission
12 shall, after notice and hearing, enter its order approving, or
13 approving as modified, or denying each such petition within
14 150 days after the filing of the petition.

15 In no event, absent General Assembly approval, shall the
16 capital investment costs incurred by a participating utility
17 other than a combination utility in satisfying its
18 infrastructure investment program commitments described in
19 subsection (b) of this Section exceed \$3,000,000,000 or, for a
20 participating utility that is a combination utility,
21 \$720,000,000. If the participating utility's updated cost
22 estimates for satisfying its infrastructure investment program
23 commitments described in subsection (b) of this Section exceed
24 the limitation imposed by this subsection (b-5), then it shall
25 submit a report to the Commission that identifies the
26 increased costs and explains the reason or reasons for the

1 increased costs no later than the year in which the utility
2 estimates it will exceed the limitation. The Commission shall
3 review the report and shall, within 90 days after the
4 participating utility files the report, report to the General
5 Assembly its findings regarding the participating utility's
6 report. If the General Assembly does not amend the limitation
7 imposed by this subsection (b-5), then the utility may modify
8 its plan so as not to exceed the limitation imposed by this
9 subsection (b-5) and may propose corresponding changes to the
10 metrics established pursuant to subparagraphs (5) through (8)
11 of subsection (f) of this Section, and the Commission may
12 modify the metrics and incremental savings goals established
13 pursuant to subsection (f) of this Section accordingly.

14 (b-10) All participating utilities shall make
15 contributions for an energy low-income and support program in
16 accordance with this subsection. Beginning no later than 180
17 days after a participating utility files a performance-based
18 formula rate tariff pursuant to subsection (c) of this
19 Section, or beginning no later than January 1, 2012 if such
20 utility files such performance-based formula rate tariff
21 within 14 days of December 30, 2011 (the effective date of
22 Public Act 97-646), and without obtaining any approvals from
23 the Commission or any other agency other than as set forth in
24 this Section, regardless of whether any such approval would
25 otherwise be required, a participating utility other than a
26 combination utility shall pay \$10,000,000 per year for 5 years

1 and a participating utility that is a combination utility
2 shall pay \$1,000,000 per year for 10 years to the energy
3 low-income and support program, which is intended to fund
4 customer assistance programs with the primary purpose being
5 avoidance of imminent disconnection. Such programs may
6 include:

7 (1) a residential hardship program that may partner
8 with community-based organizations, including senior
9 citizen organizations, and provides grants to low-income
10 residential customers, including low-income senior
11 citizens, who demonstrate a hardship;

12 (2) a program that provides grants and other bill
13 payment concessions to veterans with disabilities who
14 demonstrate a hardship and members of the armed services
15 or reserve forces of the United States or members of the
16 Illinois National Guard who are on active duty pursuant to
17 an executive order of the President of the United States,
18 an act of the Congress of the United States, or an order of
19 the Governor and who demonstrate a hardship;

20 (3) a budget assistance program that provides tools
21 and education to low-income senior citizens to assist them
22 with obtaining information regarding energy usage and
23 effective means of managing energy costs;

24 (4) a non-residential special hardship program that
25 provides grants to non-residential customers such as small
26 businesses and non-profit organizations that demonstrate a

1 hardship, including those providing services to senior
2 citizen and low-income customers; and

3 (5) a performance-based assistance program that
4 provides grants to encourage residential customers to make
5 on-time payments by matching a portion of the customer's
6 payments or providing credits towards arrearages.

7 The payments made by a participating utility pursuant to
8 this subsection (b-10) shall not be a recoverable expense. A
9 participating utility may elect to fund either new or existing
10 customer assistance programs, including, but not limited to,
11 those that are administered by the utility.

12 Programs that use funds that are provided by a
13 participating utility to reduce utility bills may be
14 implemented through tariffs that are filed with and reviewed
15 by the Commission. If a utility elects to file tariffs with the
16 Commission to implement all or a portion of the programs,
17 those tariffs shall, regardless of the date actually filed, be
18 deemed accepted and approved, and shall become effective on
19 December 30, 2011 (the effective date of Public Act 97-646).
20 The participating utilities whose customers benefit from the
21 funds that are disbursed as contemplated in this Section shall
22 file annual reports documenting the disbursement of those
23 funds with the Commission. The Commission has the authority to
24 audit disbursement of the funds to ensure they were disbursed
25 consistently with this Section.

26 If the Commission finds that a participating utility is no

1 longer eligible to update the performance-based formula rate
2 tariff pursuant to subsection (d) of this Section, or the
3 performance-based formula rate is otherwise terminated, then
4 the participating utility's voluntary commitments and
5 obligations under this subsection (b-10) shall immediately
6 terminate.

7 (b-15) Beginning in 2022, without obtaining any approvals
8 from the Commission or any other agency, regardless of whether
9 any such approval would otherwise be required, a participating
10 utility that is a combination utility shall pay \$1,000,000 per
11 year for 10 years to the energy low-income and support
12 program, which is intended to fund customer assistance
13 programs with the primary purpose of avoidance of imminent
14 disconnection and reconnecting customers who have been
15 disconnected for nonpayment. Such programs may include those
16 described in paragraphs (1) through (5) of subsection (b-10)
17 of this Section.

18 The payments made by a participating utility pursuant to
19 this subsection (b-15) is not a recoverable expense. A
20 participating utility may elect to fund either new or existing
21 customer assistance programs, including, but not limited to,
22 those that are administered by the utility.

23 Programs that use funds that are provided by a
24 participating utility to reduce utility bills may be
25 implemented through tariffs that are filed with and reviewed
26 by the Commission. If a utility elects to file tariffs with the

1 Commission to implement all or a portion of the programs,
2 those tariffs shall, regardless of the date actually filed, be
3 deemed accepted and approved, and shall become effective on
4 the first business day after they are filed. The participating
5 utilities whose customers benefit from the funds that are
6 disbursed as contemplated in this subsection (b-15) shall file
7 annual reports documenting the disbursement of those funds
8 with the Commission. The Commission has the authority to audit
9 disbursement of the funds to ensure they were disbursed
10 consistently with this subsection (b-15).

11 If the Commission finds that a participating utility is no
12 longer eligible to update the performance-based formula rate
13 tariff pursuant to subsection (d) of this Section, or the
14 performance-based formula rate is otherwise terminated, then
15 the participating utility's voluntary commitments and
16 obligations under this subsection (b-15) shall immediately
17 terminate.

18 (c) A participating utility may elect to recover its
19 delivery services costs through a performance-based formula
20 rate approved by the Commission, which shall specify the cost
21 components that form the basis of the rate charged to
22 customers with sufficient specificity to operate in a
23 standardized manner and be updated annually with transparent
24 information that reflects the utility's actual costs to be
25 recovered during the applicable rate year, which is the period
26 beginning with the first billing day of January and extending

1 through the last billing day of the following December. In the
2 event the utility recovers a portion of its costs through
3 automatic adjustment clause tariffs on October 26, 2011 (the
4 effective date of Public Act 97-616), the utility may elect to
5 continue to recover these costs through such tariffs, but then
6 these costs shall not be recovered through the
7 performance-based formula rate. In the event the participating
8 utility, prior to December 30, 2011 (the effective date of
9 Public Act 97-646), filed electric delivery services tariffs
10 with the Commission pursuant to Section 9-201 of this Act that
11 are related to the recovery of its electric delivery services
12 costs that are still pending on December 30, 2011 (the
13 effective date of Public Act 97-646), the participating
14 utility shall, at the time it files its performance-based
15 formula rate tariff with the Commission, also file a notice of
16 withdrawal with the Commission to withdraw the electric
17 delivery services tariffs previously filed pursuant to Section
18 9-201 of this Act. Upon receipt of such notice, the Commission
19 shall dismiss with prejudice any docket that had been
20 initiated to investigate the electric delivery services
21 tariffs filed pursuant to Section 9-201 of this Act, and such
22 tariffs and the record related thereto shall not be the
23 subject of any further hearing, investigation, or proceeding
24 of any kind related to rates for electric delivery services.

25 The performance-based formula rate shall be implemented
26 through a tariff filed with the Commission consistent with the

1 provisions of this subsection (c) that shall be applicable to
2 all delivery services customers. The Commission shall initiate
3 and conduct an investigation of the tariff in a manner
4 consistent with the provisions of this subsection (c) and the
5 provisions of Article IX of this Act to the extent they do not
6 conflict with this subsection (c). Except in the case where
7 the Commission finds, after notice and hearing, that a
8 participating utility is not satisfying its investment amount
9 commitments under subsection (b) of this Section, the
10 performance-based formula rate shall remain in effect at the
11 discretion of the utility. The performance-based formula rate
12 approved by the Commission shall do the following:

13 (1) Provide for the recovery of the utility's actual
14 costs of delivery services that are prudently incurred and
15 reasonable in amount consistent with Commission practice
16 and law. The sole fact that a cost differs from that
17 incurred in a prior calendar year or that an investment is
18 different from that made in a prior calendar year shall
19 not imply the imprudence or unreasonableness of that cost
20 or investment.

21 (2) Reflect the utility's actual year-end capital
22 structure for the applicable calendar year, excluding
23 goodwill, subject to a determination of prudence and
24 reasonableness consistent with Commission practice and
25 law. To enable the financing of the incremental capital
26 expenditures, including regulatory assets, for electric

1 utilities that serve less than 3,000,000 retail customers
2 but more than 500,000 retail customers in the State, a
3 participating electric utility's actual year-end capital
4 structure that includes a common equity ratio, excluding
5 goodwill, of up to and including 54% ~~50%~~ of the total
6 capital structure shall be deemed reasonable and used to
7 set rates.

8 (3) Include a cost of equity, which in all years for a
9 participating utility that is not a combination utility,
10 and in each calendar year commencing before January 1,
11 2021 for a participating utility that is a combination
12 utility, shall be calculated as the sum of the following:

13 (A) the average for the applicable calendar year
14 of the monthly average yields of 30-year U.S. Treasury
15 bonds published by the Board of Governors of the
16 Federal Reserve System in its weekly H.15 Statistical
17 Release or successor publication; and

18 (B) 580 basis points.

19 For a participating utility that is a combination
20 utility, for each calendar year commencing after December
21 31, 2020, the cost of equity shall be equal to the national
22 average cost of equity as calculated under this paragraph
23 (3). For purposes of this paragraph (3), the national
24 average cost of equity for an applicable calendar year
25 shall be the simple average of the cost of equity
26 specified and approved in each order of a state regulatory

1 commission, other than the Commission, issued during such
2 calendar year that is applicable to base rates for retail
3 electric service provided by an investor-owned public
4 utility company operating in the United States. No order
5 shall be excluded from the national average cost of equity
6 calculated under this paragraph (3) on the grounds that it
7 was arrived at by stipulation or agreement or is subject
8 to rehearing or appeal. In its final order in the
9 proceeding occurring pursuant to subsection (d) of this
10 Section during calendar year 2021, the Commission shall
11 set the cost of equity using the method applicable to
12 calendar years commencing prior to January 1, 2021. In its
13 final orders in the proceedings occurring pursuant to
14 subsection (d) of this Section in years subsequent to
15 calendar year 2021, including the reconciliation of the
16 2021 rate year, the Commission shall set the cost of
17 equity using the method applicable to calendar years
18 commencing after December 31, 2020. If, for any calendar
19 year, there are fewer than 15 applicable orders of state
20 regulatory commissions with which to compute the average
21 cost of equity, the Commission shall include in the
22 calculation of the national average the number of state
23 regulatory orders from the year or years immediately
24 preceding such calendar year necessary to reach a total of
25 15, beginning with the most recently issued and proceeding
26 in reverse chronological order.

1 At such time as the Board of Governors of the Federal
2 Reserve System ceases to include the monthly average
3 yields of 30-year U.S. Treasury bonds in its weekly H.15
4 Statistical Release or successor publication, the monthly
5 average yields of the U.S. Treasury bonds then having the
6 longest duration published by the Board of Governors in
7 its weekly H.15 Statistical Release or successor
8 publication shall instead be used for purposes of this
9 paragraph (3).

10 (4) Permit and set forth protocols, subject to a
11 determination of prudence and reasonableness consistent
12 with Commission practice and law, for the following:

13 (A) recovery of incentive compensation expense
14 that is based on the achievement of operational
15 metrics, including metrics related to budget controls,
16 outage duration and frequency, safety, customer
17 service, efficiency and productivity, and
18 environmental compliance. Incentive compensation
19 expense that is based on net income or an affiliate's
20 earnings per share shall not be recoverable under the
21 performance-based formula rate;

22 (B) recovery of pension and other post-employment
23 benefits expense, provided that such costs are
24 supported by an actuarial study;

25 (C) recovery of severance costs, provided that if
26 the amount is over \$3,700,000 for a participating

1 utility that is a combination utility or \$10,000,000
2 for a participating utility that serves more than 3
3 million retail customers, then the full amount shall
4 be amortized consistent with subparagraph (F) of this
5 paragraph (4);

6 (D) investment return at a rate equal to the
7 utility's weighted average cost of long-term debt, on
8 the pension assets as, and in the amount, reported in
9 Account 186 (or in such other Account or Accounts as
10 such asset may subsequently be recorded) of the
11 utility's most recently filed FERC Form 1, net of
12 deferred tax benefits;

13 (E) recovery of the expenses related to the
14 Commission proceeding under this subsection (c) to
15 approve this performance-based formula rate and
16 initial rates or to subsequent proceedings related to
17 the formula, provided that the recovery shall be
18 amortized over a 3-year period; recovery of expenses
19 related to the annual Commission proceedings under
20 subsection (d) of this Section to review the inputs to
21 the performance-based formula rate shall be expensed
22 and recovered through the performance-based formula
23 rate;

24 (F) amortization over a 5-year period of the full
25 amount of each charge or credit that exceeds
26 \$3,700,000 for a participating utility that is a

1 combination utility or \$10,000,000 for a participating
2 utility that serves more than 3 million retail
3 customers in the applicable calendar year and that
4 relates to a workforce reduction program's severance
5 costs, changes in accounting rules, changes in law,
6 compliance with any Commission-initiated audit, or a
7 single storm or other similar expense, provided that
8 any unamortized balance shall be reflected in rate
9 base. For purposes of this subparagraph (F), changes
10 in law includes any enactment, repeal, or amendment in
11 a law, ordinance, rule, regulation, interpretation,
12 permit, license, consent, or order, including those
13 relating to taxes, accounting, or to environmental
14 matters, or in the interpretation or application
15 thereof by any governmental authority occurring after
16 October 26, 2011 (the effective date of Public Act
17 97-616);

18 (G) recovery of existing regulatory assets over
19 the periods previously authorized by the Commission;

20 (H) historical weather normalized billing
21 determinants; and

22 (I) allocation methods for common costs.

23 (5) Provide that if the participating utility's earned
24 rate of return on common equity related to the provision
25 of delivery services for the prior rate year (calculated
26 using costs and capital structure approved by the

1 Commission as provided in subparagraph (2) of this
2 subsection (c), consistent with this Section, in
3 accordance with Commission rules and orders, including,
4 but not limited to, adjustments for goodwill, and after
5 any Commission-ordered disallowances and taxes) is more
6 than 50 basis points higher than the rate of return on
7 common equity calculated pursuant to paragraph (3) of this
8 subsection (c) (after ~~adjusting for~~ any adjustments
9 ~~penalties~~ to the rate of return on common equity applied
10 pursuant to the performance metrics provision of
11 subsections ~~subsection~~ (f), (f-5), (f-10), or (f-15) of
12 this Section, as applicable), then the participating
13 utility shall apply a credit through the performance-based
14 formula rate that reflects an amount equal to the value of
15 that portion of the earned rate of return on common equity
16 that is more than 50 basis points higher than the rate of
17 return on common equity calculated pursuant to paragraph
18 (3) of this subsection (c) (after ~~adjusting for~~ any
19 adjustments ~~penalties~~ to the rate of return on common
20 equity applied pursuant to the performance metrics
21 provision of subsections ~~subsection~~ (f), (f-5), (f-10), or
22 (f-15) of this Section, as applicable) for the prior rate
23 year, adjusted for taxes. If the participating utility's
24 earned rate of return on common equity related to the
25 provision of delivery services for the prior rate year
26 (calculated using costs and capital structure approved by

1 the Commission as provided in subparagraph (2) of this
2 subsection (c), consistent with this Section, in
3 accordance with Commission rules and orders, including,
4 but not limited to, adjustments for goodwill, and after
5 any Commission-ordered disallowances and taxes) is more
6 than 50 basis points less than the return on common equity
7 calculated pursuant to paragraph (3) of this subsection
8 (c) (after ~~adjusting for any adjustments penalties~~ to the
9 rate of return on common equity applied pursuant to the
10 performance metrics provision of subsections ~~subsection~~
11 (f), (f-5), (f-10), or (f-15) of this Section, as
12 applicable), then the participating utility shall apply a
13 charge through the performance-based formula rate that
14 reflects an amount equal to the value of that portion of
15 the earned rate of return on common equity that is more
16 than 50 basis points less than the rate of return on common
17 equity calculated pursuant to paragraph (3) of this
18 subsection (c) (after ~~adjusting for any adjustments~~
19 ~~penalties~~ to the rate of return on common equity applied
20 pursuant to the performance metrics provision of
21 subsections ~~subsection~~ (f), (f-5), (f-10), or (f-15) of
22 this Section, as applicable) for the prior rate year,
23 adjusted for taxes.

24 (6) Provide for an annual reconciliation, as described
25 in subsection (d) of this Section, with interest, of the
26 revenue requirement reflected in rates for each calendar

1 year, beginning with the calendar year in which the
2 utility files its performance-based formula rate tariff
3 pursuant to subsection (c) of this Section, with what the
4 revenue requirement would have been had the actual cost
5 information for the applicable calendar year been
6 available at the filing date.

7 The utility shall file, together with its tariff, final
8 data based on its most recently filed FERC Form 1, plus
9 projected plant additions and correspondingly updated
10 depreciation reserve and expense for the calendar year in
11 which the tariff and data are filed, that shall populate the
12 performance-based formula rate and set the initial delivery
13 services rates under the formula. For purposes of this
14 Section, "FERC Form 1" means the Annual Report of Major
15 Electric Utilities, Licensees and Others that electric
16 utilities are required to file with the Federal Energy
17 Regulatory Commission under the Federal Power Act, Sections 3,
18 4(a), 304 and 209, modified as necessary to be consistent with
19 83 Ill. Admin. Code Part 415 as of May 1, 2011. Nothing in this
20 Section is intended to allow costs that are not otherwise
21 recoverable to be recoverable by virtue of inclusion in FERC
22 Form 1.

23 After the utility files its proposed performance-based
24 formula rate structure and protocols and initial rates, the
25 Commission shall initiate a docket to review the filing. The
26 Commission shall enter an order approving, or approving as

1 modified, the performance-based formula rate, including the
2 initial rates, as just and reasonable within 270 days after
3 the date on which the tariff was filed, or, if the tariff is
4 filed within 14 days after October 26, 2011 (the effective
5 date of Public Act 97-616), then by May 31, 2012. Such review
6 shall be based on the same evidentiary standards, including,
7 but not limited to, those concerning the prudence and
8 reasonableness of the costs incurred by the utility, the
9 Commission applies in a hearing to review a filing for a
10 general increase in rates under Article IX of this Act. The
11 initial rates shall take effect within 30 days after the
12 Commission's order approving the performance-based formula
13 rate tariff.

14 Until such time as the Commission approves a different
15 rate design and cost allocation pursuant to subsection (e) of
16 this Section, rate design and cost allocation across customer
17 classes shall be consistent with the Commission's most recent
18 order regarding the participating utility's request for a
19 general increase in its delivery services rates.

20 Subsequent changes to the performance-based formula rate
21 structure or protocols shall be made as set forth in Section
22 9-201 of this Act, but nothing in this subsection (c) is
23 intended to limit the Commission's authority under Article IX
24 and other provisions of this Act to initiate an investigation
25 of a participating utility's performance-based formula rate
26 tariff, provided that any such changes shall be consistent

1 with paragraphs (1) through (6) of this subsection (c). Any
2 change ordered by the Commission shall be made at the same time
3 new rates take effect following the Commission's next order
4 pursuant to subsection (d) of this Section, provided that the
5 new rates take effect no less than 30 days after the date on
6 which the Commission issues an order adopting the change.

7 A participating utility that files a tariff pursuant to
8 this subsection (c) must submit a one-time \$200,000 filing fee
9 at the time the Chief Clerk of the Commission accepts the
10 filing, which shall be a recoverable expense.

11 In the event the performance-based formula rate is
12 terminated, the then current rates shall remain in effect
13 until such time as new rates are set pursuant to Article IX of
14 this Act, subject to retroactive rate adjustment, with
15 interest, to reconcile rates charged with actual costs. At
16 such time that the performance-based formula rate is
17 terminated, the participating utility's voluntary commitments
18 and obligations under subsection (b) of this Section shall
19 immediately terminate, except for the utility's obligation to
20 pay an amount already owed to the fund for training grants
21 pursuant to a Commission order issued under subsection (b) of
22 this Section.

23 (c-5) Beginning in the first calendar year following the
24 year in which this reporting requirement becomes effective, a
25 participating utility that is a combination utility shall,
26 within 45 days after the close of each of the participating

1 utility that is a combination utility's fiscal quarters,
2 submit to the Commission a report that summarizes the
3 additions to utility plant that were placed into service
4 during the prior quarter, which for purposes of the report
5 shall be the most recently closed fiscal quarter, as well as
6 what utility plant the participating utility that is a
7 combination utility projects will place into service through
8 the end of the calendar year in which the report is filed. The
9 quarterly report provided will be used for informational
10 purposes only, and any estimates therein shall not bind or
11 limit the participating utility that is a combination
12 utility's future decisions to invest in any utility plant or
13 other projects and may not be used in any Commission
14 proceeding to support any finding as to imprudence,
15 unreasonableness, or lack of use or usefulness of any
16 individual or aggregate level of utility plant or other
17 investment. Within 7 days of receiving a quarterly report, the
18 Commission shall make the report available to the public. Each
19 quarterly report shall include the following detail:

20 (1) the total dollar value of the additions to utility
21 plant placed in service during the prior quarter;

22 (2) a list of standing work orders for utility plant
23 placed in service during the prior quarter, including the
24 total dollar amount for the work reflected in each
25 standing work order as of the last day of the quarterly
26 reporting period and a summary description of the standing

1 work order;

2 (3) a list of specific work orders for utility plant
3 placed in service during the prior quarter for utility
4 plant placed in service with a total dollar value as of the
5 last day of the quarterly reporting period that is equal
6 to or greater than \$500,000, inclusive of the dollar
7 amount reflected in each specific work order and a summary
8 description of the specific work order;

9 (4) the estimated total dollar value of the additions
10 to utility plant projected to be placed in service through
11 the end of the calendar year in which the report is filed;

12 (5) a list of standing work orders for utility plant
13 projected to be placed in service through the end of the
14 calendar year in which the report is filed, including the
15 estimated dollar amount for the work reflected in each
16 standing work order and a summary description of the
17 standing work order; and

18 (6) a list of specific work orders for utility plant
19 projected to be placed in service through the end of the
20 calendar year in which the report is filed with an
21 estimated dollar value that is equal to or greater than
22 \$500,000, inclusive of the estimated dollar amount for the
23 work reflected in each specific work order and a summary
24 description of the specific work order.

25 (d) Subsequent to the Commission's issuance of an order
26 approving the utility's performance-based formula rate

1 structure and protocols, and initial rates under subsection
2 (c) of this Section, the utility shall file, on or before May 1
3 of each year, with the Chief Clerk of the Commission its
4 updated cost inputs to the performance-based formula rate for
5 the applicable rate year and the corresponding new charges.
6 Each such filing shall conform to the following requirements
7 and include the following information:

8 (1) The inputs to the performance-based formula rate
9 for the applicable rate year shall be based on final
10 historical data reflected in the utility's most recently
11 filed annual FERC Form 1 plus projected plant additions
12 and correspondingly updated depreciation reserve and
13 expense for the calendar year in which the inputs are
14 filed. The filing shall also include a reconciliation of
15 the revenue requirement that was in effect for the prior
16 rate year (as set by the cost inputs for the prior rate
17 year) with the actual revenue requirement for the prior
18 rate year (determined using a year-end rate base) that
19 uses amounts reflected in the applicable FERC Form 1 that
20 reports the actual costs for the prior rate year. Any
21 over-collection or under-collection indicated by such
22 reconciliation shall be reflected as a credit against, or
23 recovered as an additional charge to, respectively, with
24 interest calculated at a rate equal to the utility's
25 weighted average cost of capital approved by the
26 Commission for the prior rate year, the charges for the

1 applicable rate year. Provided, however, that the first
2 such reconciliation shall be for the calendar year in
3 which the utility files its performance-based formula rate
4 tariff pursuant to subsection (c) of this Section and
5 shall reconcile (i) the revenue requirement or
6 requirements established by the rate order or orders in
7 effect from time to time during such calendar year
8 (weighted, as applicable) with (ii) the revenue
9 requirement determined using a year-end rate base for that
10 calendar year calculated pursuant to the performance-based
11 formula rate using (A) actual costs for that year as
12 reflected in the applicable FERC Form 1, and (B) for the
13 first such reconciliation only, the cost of equity, which
14 shall be calculated as the sum of 590 basis points plus the
15 average for the applicable calendar year of the monthly
16 average yields of 30-year U.S. Treasury bonds published by
17 the Board of Governors of the Federal Reserve System in
18 its weekly H.15 Statistical Release or successor
19 publication. The first such reconciliation is not intended
20 to provide for the recovery of costs previously excluded
21 from rates based on a prior Commission order finding of
22 imprudence or unreasonableness. Each reconciliation shall
23 be certified by the participating utility in the same
24 manner that FERC Form 1 is certified. The filing shall
25 also include the charge or credit, if any, resulting from
26 the calculation required by paragraph (6) of subsection

1 (c) of this Section.

2 Notwithstanding anything that may be to the contrary,
3 the intent of the reconciliation is to ultimately
4 reconcile the revenue requirement reflected in rates for
5 each calendar year, beginning with the calendar year in
6 which the utility files its performance-based formula rate
7 tariff pursuant to subsection (c) of this Section, with
8 what the revenue requirement determined using a year-end
9 rate base for the applicable calendar year would have been
10 had the actual cost information for the applicable
11 calendar year been available at the filing date.

12 (2) The new charges shall take effect beginning on the
13 first billing day of the following January billing period
14 and remain in effect through the last billing day of the
15 next December billing period regardless of whether the
16 Commission enters upon a hearing pursuant to this
17 subsection (d).

18 (3) The filing shall include relevant and necessary
19 data and documentation for the applicable rate year that
20 is consistent with the Commission's rules applicable to a
21 filing for a general increase in rates or any rules
22 adopted by the Commission to implement this Section.
23 Normalization adjustments shall not be required.
24 Notwithstanding any other provision of this Section or Act
25 or any rule or other requirement adopted by the
26 Commission, a participating utility that is a combination

1 utility with more than one rate zone shall not be required
2 to file a separate set of such data and documentation for
3 each rate zone and may combine such data and documentation
4 into a single set of schedules.

5 Within 45 days after the utility files its annual update
6 of cost inputs to the performance-based formula rate, the
7 Commission shall have the authority, either upon complaint or
8 its own initiative, but with reasonable notice, to enter upon
9 a hearing concerning the prudence and reasonableness of the
10 costs incurred by the utility to be recovered during the
11 applicable rate year that are reflected in the inputs to the
12 performance-based formula rate derived from the utility's FERC
13 Form 1. During the course of the hearing, each objection shall
14 be stated with particularity and evidence provided in support
15 thereof, after which the utility shall have the opportunity to
16 rebut the evidence. Discovery shall be allowed consistent with
17 the Commission's Rules of Practice, which Rules shall be
18 enforced by the Commission or the assigned administrative law
19 judge. The Commission shall apply the same evidentiary
20 standards, including, but not limited to, those concerning the
21 prudence and reasonableness of the costs incurred by the
22 utility, in the hearing as it would apply in a hearing to
23 review a filing for a general increase in rates under Article
24 IX of this Act. The Commission shall not, however, have the
25 authority in a proceeding under this subsection (d) to
26 consider or order any changes to the structure or protocols of

1 the performance-based formula rate approved pursuant to
2 subsection (c) of this Section. In a proceeding under this
3 subsection (d), the Commission shall enter its order no later
4 than the earlier of 240 days after the utility's filing of its
5 annual update of cost inputs to the performance-based formula
6 rate or December 31. The Commission's determinations of the
7 prudence and reasonableness of the costs incurred for the
8 applicable calendar year shall be final upon entry of the
9 Commission's order and shall not be subject to reopening,
10 reexamination, or collateral attack in any other Commission
11 proceeding, case, docket, order, rule or regulation, provided,
12 however, that nothing in this subsection (d) shall prohibit a
13 party from petitioning the Commission to rehear or appeal to
14 the courts the order pursuant to the provisions of this Act.

15 In the event the Commission does not, either upon
16 complaint or its own initiative, enter upon a hearing within
17 45 days after the utility files the annual update of cost
18 inputs to its performance-based formula rate, then the costs
19 incurred for the applicable calendar year shall be deemed
20 prudent and reasonable, and the filed charges shall not be
21 subject to reopening, reexamination, or collateral attack in
22 any other proceeding, case, docket, order, rule, or
23 regulation.

24 A participating utility's first filing of the updated cost
25 inputs, and any Commission investigation of such inputs
26 pursuant to this subsection (d) shall proceed notwithstanding

1 the fact that the Commission's investigation under subsection
2 (c) of this Section is still pending and notwithstanding any
3 other law, order, rule, or Commission practice to the
4 contrary.

5 (e) Nothing in subsections (c) or (d) of this Section
6 shall prohibit the Commission from investigating, or a
7 participating utility from filing, revenue-neutral tariff
8 changes related to rate design of a performance-based formula
9 rate that has been placed into effect for the utility.
10 Following approval of a participating utility's
11 performance-based formula rate tariff pursuant to subsection
12 (c) of this Section, the utility shall make a filing with the
13 Commission within one year after the effective date of the
14 performance-based formula rate tariff that proposes changes to
15 the tariff to incorporate the findings of any final rate
16 design orders of the Commission applicable to the
17 participating utility and entered subsequent to the
18 Commission's approval of the tariff. The Commission shall,
19 after notice and hearing, enter its order approving, or
20 approving with modification, the proposed changes to the
21 performance-based formula rate tariff within 240 days after
22 the utility's filing. Following such approval, the utility
23 shall make a filing with the Commission during each subsequent
24 3-year period that either proposes revenue-neutral tariff
25 changes or re-files the existing tariffs without change, which
26 shall present the Commission with an opportunity to suspend

1 the tariffs and consider revenue-neutral tariff changes
2 related to rate design.

3 (f) Within 30 days after the filing of a tariff pursuant to
4 subsection (c) of this Section, each participating utility
5 shall develop and file with the Commission multi-year metrics
6 designed to achieve, ratably (i.e., in equal segments) over a
7 10-year period, improvement over baseline performance values
8 as follows:

9 (1) Twenty percent improvement in the System Average
10 Interruption Frequency Index, using a baseline of the
11 average of the data from 2001 through 2010.

12 (2) Fifteen percent improvement in the system Customer
13 Average Interruption Duration Index, using a baseline of
14 the average of the data from 2001 through 2010.

15 (3) For a participating utility other than a
16 combination utility, 20% improvement in the System Average
17 Interruption Frequency Index for its Southern Region,
18 using a baseline of the average of the data from 2001
19 through 2010. For purposes of this paragraph (3), Southern
20 Region shall have the meaning set forth in the
21 participating utility's most recent report filed pursuant
22 to Section 16-125 of this Act.

23 (3.5) For a participating utility other than a
24 combination utility, 20% improvement in the System Average
25 Interruption Frequency Index for its Northeastern Region,
26 using a baseline of the average of the data from 2001

1 through 2010. For purposes of this paragraph (3.5),
2 Northeastern Region shall have the meaning set forth in
3 the participating utility's most recent report filed
4 pursuant to Section 16-125 of this Act.

5 (4) Seventy-five percent improvement in the total
6 number of customers who exceed the service reliability
7 targets as set forth in subparagraphs (A) through (C) of
8 paragraph (4) of subsection (b) of 83 Ill. Admin. Code
9 Part 411.140 as of May 1, 2011, using 2010 as the baseline
10 year.

11 (5) Reduction in issuance of estimated electric bills:
12 90% improvement for a participating utility other than a
13 combination utility, and 56% improvement for a
14 participating utility that is a combination utility, using
15 a baseline of the average number of estimated bills for
16 the years 2008 through 2010.

17 (6) Consumption on inactive meters: 90% improvement
18 for a participating utility other than a combination
19 utility, and 56% improvement for a participating utility
20 that is a combination utility, using a baseline of the
21 average unbilled kilowatthours for the years 2009 and
22 2010.

23 (7) Unaccounted for energy: 50% improvement for a
24 participating utility other than a combination utility
25 using a baseline of the non-technical line loss
26 unaccounted for energy kilowatthours for the year 2009.

1 (8) Uncollectible expense: reduce uncollectible
2 expense by at least \$30,000,000 for a participating
3 utility other than a combination utility and by at least
4 \$3,500,000 for a participating utility that is a
5 combination utility, using a baseline of the average
6 uncollectible expense for the years 2008 through 2010.

7 (9) Opportunities for minority-owned and woman-owned
8 ~~female-owned~~ business enterprises: design a performance
9 metric regarding the creation of opportunities for
10 minority-owned and woman-owned ~~female-owned~~ business
11 enterprises consistent with State and federal law using a
12 base performance value of the percentage of the
13 participating utility's capital expenditures that were
14 paid to minority-owned and woman-owned ~~female-owned~~
15 business enterprises in 2010.

16 The definitions set forth in 83 Ill. Admin. Code Part
17 411.20 as of May 1, 2011 shall be used for purposes of
18 calculating performance under paragraphs (1) through (3.5) of
19 this subsection (f), provided, however, that the participating
20 utility may exclude up to 9 extreme weather event days from
21 such calculation for each year, and provided further that the
22 participating utility shall exclude 9 extreme weather event
23 days when calculating each year of the baseline period to the
24 extent that there are 9 such days in a given year of the
25 baseline period. For purposes of this Section, an extreme
26 weather event day is a 24-hour calendar day (beginning at

1 12:00 a.m. and ending at 11:59 p.m.) during which any weather
2 event (e.g., storm, tornado) caused interruptions for 10,000
3 or more of the participating utility's customers for 3 hours
4 or more. If there are more than 9 extreme weather event days in
5 a year, then the utility may choose no more than 9 extreme
6 weather event days to exclude, provided that the same extreme
7 weather event days are excluded from each of the calculations
8 performed under paragraphs (1) through (3.5) of this
9 subsection (f).

10 The metrics shall include incremental performance goals
11 for each year of the 10-year period, which shall be designed to
12 demonstrate that the utility is on track to achieve the
13 performance goal in each category at the end of the 10-year
14 period. The utility shall elect when the 10-year period shall
15 commence for the metrics set forth in subparagraphs (1)
16 through (4) and (9) of this subsection (f), provided that it
17 begins no later than 14 months following the date on which the
18 utility begins investing pursuant to subsection (b) of this
19 Section, and when the 10-year period shall commence for the
20 metrics set forth in subparagraphs (5) through (8) of this
21 subsection (f), provided that it begins no later than 14
22 months following the date on which the Commission enters its
23 order approving the utility's Advanced Metering Infrastructure
24 Deployment Plan pursuant to subsection (c) of Section 16-108.6
25 of this Act.

26 The metrics and performance goals set forth in

1 subparagraphs (5) through (8) of this subsection (f) are based
2 on the assumptions that the participating utility may fully
3 implement the technology described in subsection (b) of this
4 Section, including utilizing the full functionality of such
5 technology and that there is no requirement for personal
6 on-site notification. If the utility is unable to meet the
7 metrics and performance goals set forth in subparagraphs (5)
8 through (8) of this subsection (f) for such reasons, and the
9 Commission so finds after notice and hearing, then the utility
10 shall be excused from compliance, but only to the limited
11 extent achievement of the affected metrics and performance
12 goals was hindered by the less than full implementation.

13 (f-5) The financial penalties applicable to the metrics
14 described in subparagraphs (1) through (8) of subsection (f)
15 of this Section, as applicable, shall be applied through an
16 adjustment to the participating utility's return on equity of
17 no more than a total of 30 basis points in each of the first 3
18 years, of no more than a total of 34 basis points in each of
19 the 3 years thereafter, and of no more than a total of 38 basis
20 points in each of the 4 years thereafter, as follows:

21 (1) With respect to each of the incremental annual
22 performance goals established pursuant to paragraph (1) of
23 subsection (f) of this Section,

24 (A) for each year that a participating utility
25 other than a combination utility does not achieve the
26 annual goal, the participating utility's return on

1 equity shall be reduced as follows: during years 1
2 through 3, by 5 basis points; during years 4 through 6,
3 by 6 basis points; and during years 7 through 10, by 7
4 basis points; and

5 (B) for each year that a participating utility
6 that is a combination utility does not achieve the
7 annual goal, the participating utility's return on
8 equity shall be reduced as follows: during years 1
9 through 3, by 10 basis points; during years 4 through
10 6, by 12 basis points; and during years 7 through 10,
11 by 14 basis points.

12 (2) With respect to each of the incremental annual
13 performance goals established pursuant to paragraph (2) of
14 subsection (f) of this Section, for each year that the
15 participating utility does not achieve each such goal, the
16 participating utility's return on equity shall be reduced
17 as follows: during years 1 through 3, by 5 basis points;
18 during years 4 through 6, by 6 basis points; and during
19 years 7 through 10, by 7 basis points.

20 (3) With respect to each of the incremental annual
21 performance goals established pursuant to paragraphs (3)
22 and (3.5) of subsection (f) of this Section, for each year
23 that a participating utility other than a combination
24 utility does not achieve both such goals, the
25 participating utility's return on equity shall be reduced
26 as follows: during years 1 through 3, by 5 basis points;

1 during years 4 through 6, by 6 basis points; and during
2 years 7 through 10, by 7 basis points.

3 (4) With respect to each of the incremental annual
4 performance goals established pursuant to paragraph (4) of
5 subsection (f) of this Section, for each year that the
6 participating utility does not achieve each such goal, the
7 participating utility's return on equity shall be reduced
8 as follows: during years 1 through 3, by 5 basis points;
9 during years 4 through 6, by 6 basis points; and during
10 years 7 through 10, by 7 basis points.

11 (5) With respect to each of the incremental annual
12 performance goals established pursuant to subparagraph (5)
13 of subsection (f) of this Section, for each year that the
14 participating utility does not achieve at least 95% of
15 each such goal, the participating utility's return on
16 equity shall be reduced by 5 basis points for each such
17 unachieved goal.

18 (6) With respect to each of the incremental annual
19 performance goals established pursuant to paragraphs (6),
20 (7), and (8) of subsection (f) of this Section, as
21 applicable, which together measure non-operational
22 customer savings and benefits relating to the
23 implementation of the Advanced Metering Infrastructure
24 Deployment Plan, as defined in Section 16-108.6 of this
25 Act, the performance under each such goal shall be
26 calculated in terms of the percentage of the goal

1 achieved. The percentage of goal achieved for each of the
2 goals shall be aggregated, and an average percentage value
3 calculated, for each year of the 10-year period. If the
4 utility does not achieve an average percentage value in a
5 given year of at least 95%, the participating utility's
6 return on equity shall be reduced by 5 basis points.

7 The financial penalties shall be applied as described in
8 this subsection (f-5) for the 12-month period in which the
9 deficiency occurred through a separate tariff mechanism, which
10 shall be filed by the utility together with its metrics. In the
11 event the formula rate tariff established pursuant to
12 subsection (c) of this Section terminates, the utility's
13 obligations under subsection (f) of this Section and this
14 subsection (f-5) shall also terminate, provided, however, that
15 the tariff mechanism established pursuant to subsection (f) of
16 this Section and this subsection (f-5) shall remain in effect
17 until any penalties due and owing at the time of such
18 termination are applied.

19 The Commission shall, after notice and hearing, enter an
20 order within 120 days after the metrics are filed approving,
21 or approving with modification, a participating utility's
22 tariff or mechanism to satisfy the metrics set forth in
23 subsection (f) of this Section. On June 1 of each subsequent
24 year, each participating utility shall file a report with the
25 Commission that includes, among other things, a description of
26 how the participating utility performed under each metric and

1 an identification of any extraordinary events that adversely
2 impacted the utility's performance. Whenever a participating
3 utility does not satisfy the metrics required pursuant to
4 subsection (f) of this Section, the Commission shall, after
5 notice and hearing, enter an order approving financial
6 penalties in accordance with this subsection (f-5). The
7 Commission-approved financial penalties shall be applied
8 beginning with the next rate year. Nothing in this Section
9 shall authorize the Commission to reduce or otherwise obviate
10 the imposition of financial penalties for failing to achieve
11 one or more of the metrics established pursuant to
12 subparagraph (1) through (4) of subsection (f) of this
13 Section.

14 (f-10) No later than December 31, 2021, a participating
15 utility that is a combination utility shall revise the tariff
16 it filed with the Commission pursuant to subsection (f) of
17 this Section to include multi-year metrics designed to achieve
18 ratably (in equal annual segments), where applicable, over the
19 10-year period beginning January 1, 2023 through December 31,
20 2032, maintenance or improvement over baseline performance
21 values as follows:

22 (1) Maintain the 20% improvement in the System Average
23 Interruption Frequency Index, using a baseline of the
24 average of the data from 2001 through 2010, achieved
25 during the initial 10-year performance period.

26 (2) Maintain the 15% improvement in the system

1 Customer Average Interruption Duration Index, using a
2 baseline of the average of the data from 2001 through
3 2010, achieved during the initial 10-year performance
4 period.

5 (3) Increase the quantity of energy produced by solar
6 facilities owned and operated by the participating utility
7 to a level greater than or equal to 250,000 MWHs per year
8 by year 5 and 1,000,000 MWHs per year by year 10, using a
9 baseline of the data for the year end 2020.

10 (4) Increase the number of solar facilities owned and
11 operated by the participating utility, located, in whole
12 or part, within 5 miles of one or more of the 50 zip codes
13 in the participating utility's service territory that
14 include the largest percentage of households at or below
15 80% of area median income, to 10, by year 10, using a
16 baseline of year end 2020.

17 (5) Decrease the average driving distance between
18 publicly accessible Level III Fast DC charging locations
19 along major charging corridors (interstate and other major
20 travel routes) within the service territory of the
21 participating utility to 50 miles or less by year 5 using a
22 baseline of year end 2020.

23 (6) Increase the total number of publicly accessible
24 Level Two charging ports within the service territory of
25 the participating utility to 2,000 by year 5 using a
26 baseline of year end 2020.

1 (7) Opportunities for minority-owned, woman-owned, and
2 veteran-owned business enterprises: design a performance
3 metric regarding the creation of opportunities for
4 minority-owned, woman-owned and veteran-owned business
5 enterprises consistent with State and federal law using a
6 base performance value of the percentage of the
7 participating utility's capital expenditures that were
8 paid to minority-owned, woman-owned and veteran-owned
9 business enterprises in the years 2018, 2019, and 2020.

10 The definitions set forth in 83 Ill. Adm. Code Part 411.20
11 as of May 1, 2011 shall be used for purposes of calculating
12 performance under paragraphs (1) and (2) of this subsection
13 (f-10), provided, however, that the participating utility may
14 exclude up to 9 extreme weather event days from such
15 calculation for each year, and provided further that the
16 participating utility shall exclude 9 extreme weather event
17 days when calculating each year of the baseline period to the
18 extent that there are 9 such days in a given year of the
19 baseline period. For purposes of this subsection (f-10), an
20 extreme weather event day is a 24-hour calendar day, beginning
21 at 12:00 a.m. and ending at 11:59 p.m., during which any
22 weather event, including but not limited to a storm or
23 tornado, caused interruptions for 3,500 or more of the
24 participating utility's customers for 3 hours or more. If
25 there are more than 9 extreme weather event days in a year,
26 then the utility may choose no more than 9 extreme weather

1 event days to exclude, provided that the same extreme weather
2 event days are excluded from each of the calculations
3 performed under paragraphs (1) and (2) of this subsection
4 (f-10).

5 (f-15) The performance-based financial adjustments
6 applicable to the metrics described in subparagraphs (1)
7 through (6) of subsection (f-10) of this Section, as
8 applicable, shall be applied through an adjustment to the
9 participating utility's return on equity of no more than a
10 total of 40 basis points in each year of the 10-year
11 performance period:

12 (1) With respect to the incremental annual performance
13 goals established pursuant to paragraph (1) of subsection
14 (f-10) of this Section, for each year that a participating
15 utility does not achieve at least 95% of the annual goal,
16 the participating utility's return on equity shall be
17 reduced as follows: during years one through 5, by 8 basis
18 points; and during years 6 through 10, by 10 basis points;
19 for each year in which the participating utility achieves
20 105% or more of such goal, the participating utility's
21 return on equity shall be increased as follows: during
22 years one through 5, by 8 basis points; and during years 6
23 through 10, by 10 basis points.

24 (2) With respect to the incremental annual performance
25 goals established pursuant to paragraph (2) of subsection
26 (f-10) of this Section, for each year that a participating

1 utility does not achieve at least 95% of the annual goal,
2 the participating utility's return on equity shall be
3 reduced as follows: during years one through 5, by 8 basis
4 points; and during years 6 through 10, by 10 basis points;
5 for each year in which the participating utility achieves
6 105% or more of such goal, the participating utility's
7 return on equity shall be increased as follows: during
8 years one through 5, by 8 basis points; and during years 6
9 through 10, by 10 basis points.

10 (3) With respect to the incremental annual performance
11 goals established pursuant to paragraph (3) of subsection
12 (f-10) of this Section, for each year that a participating
13 utility does not achieve at least 95% of the annual goal,
14 the participating utility's return on equity shall be
15 reduced as follows: during years one through 5, by 8 basis
16 points; and during years 6 through 10, by 10 basis points;
17 for each year in which the participating utility achieves
18 105% or more of such goal, the participating utility's
19 return on equity shall be increased as follows: during
20 years one through 5, by 8 basis points; and during years 6
21 through 10, by 10 basis points.

22 (4) With respect to the incremental annual performance
23 goals established pursuant to paragraph (4) of subsection
24 (f-10) of this Section, for each year that a participating
25 utility does not achieve at least 95% of the annual goal,
26 the participating utility's return on equity shall be

1 reduced as follows: during years one through 5, by 8 basis
2 points; and during years 6 through 10, by 10 basis points;
3 for each year in which the participating utility achieves
4 105% or more of such goal, the participating utility's
5 return on equity shall be increased as follows: during
6 years one through 5, by 8 basis points; and during years 6
7 through 10, by 10 basis points.

8 (5) With respect to each of the incremental annual
9 performance goals established pursuant to paragraphs (5)
10 and (6) of subsection (f-10) of this Section, the
11 performance under each such goal shall be calculated in
12 terms of the percentage of the goal achieved. The
13 percentage of the goal achieved for each of the goals
14 shall be aggregated, and an average percentage value
15 calculated. For each year that a participating utility
16 does not achieve at least 95% of the annual goal, the
17 participating utility's return on equity shall be reduced
18 as follows: during years one through 5, by 8 basis points;
19 and during years 6 through 10, by no basis points; for each
20 year in which the participating utility achieves 105% or
21 more of such goal, the participating utility's return on
22 equity shall be increased as follows: during years one
23 through 5, by 8 basis points; and during years 6 through
24 10, by no basis points.

25 The financial adjustments shall be applied as described in
26 this subsection (f-15) for the 12-month period in which the

1 performance occurred through a separate tariff mechanism,
2 which shall be filed by the utility together with its metrics.
3 In the event the performance based rate tariff established
4 pursuant to subsection (c) of this Section, terminates, the
5 utility's obligations under subsection (f), (f-5), (f-10), and
6 this subparagraph (f-15) shall also terminate, provided,
7 however, that the tariff mechanism established pursuant to
8 subsection (f-10) and this subsection (f-15) shall remain in
9 effect until the remaining balance of any financial
10 adjustments at the time of such termination is fully
11 amortized.

12 (g) On or before July 31, 2014, each participating utility
13 shall file a report with the Commission that sets forth the
14 average annual increase in the average amount paid per
15 kilowatthour for residential eligible retail customers,
16 exclusive of the effects of energy efficiency programs,
17 comparing the 12-month period ending May 31, 2012; the
18 12-month period ending May 31, 2013; and the 12-month period
19 ending May 31, 2014. For a participating utility that is a
20 combination utility with more than one rate zone, the weighted
21 average aggregate increase shall be provided. The report shall
22 be filed together with a statement from an independent auditor
23 attesting to the accuracy of the report. The cost of the
24 independent auditor shall be borne by the participating
25 utility and shall not be a recoverable expense. "The average
26 amount paid per kilowatthour" shall be based on the

1 participating utility's tariffed rates actually in effect and
2 shall not be calculated using any hypothetical rate or
3 adjustments to actual charges (other than as specified for
4 energy efficiency) as an input.

5 In the event that the average annual increase exceeds 2.5%
6 as calculated pursuant to this subsection (g), then Sections
7 16-108.5, 16-108.6, 16-108.7, and 16-108.8 of this Act, other
8 than this subsection, shall be inoperative as they relate to
9 the utility and its service area as of the date of the report
10 due to be submitted pursuant to this subsection and the
11 utility shall no longer be eligible to annually update the
12 performance-based formula rate tariff pursuant to subsection
13 (d) of this Section. In such event, the then current rates
14 shall remain in effect until such time as new rates are set
15 pursuant to Article IX of this Act, subject to retroactive
16 adjustment, with interest, to reconcile rates charged with
17 actual costs, and the participating utility's voluntary
18 commitments and obligations under subsection (b) of this
19 Section shall immediately terminate, except for the utility's
20 obligation to pay an amount already owed to the fund for
21 training grants pursuant to a Commission order issued under
22 subsection (b) of this Section.

23 In the event that the average annual increase is 2.5% or
24 less as calculated pursuant to this subsection (g), then the
25 performance-based formula rate shall remain in effect as set
26 forth in this Section.

1 For purposes of this Section, the amount per kilowatthour
2 means the total amount paid for electric service expressed on
3 a per kilowatthour basis, and the total amount paid for
4 electric service includes without limitation amounts paid for
5 supply, transmission, distribution, surcharges, and add-on
6 taxes exclusive of any increases in taxes or new taxes imposed
7 after October 26, 2011 (the effective date of Public Act
8 97-616). For purposes of this Section, "eligible retail
9 customers" shall have the meaning set forth in Section
10 16-111.5 of this Act.

11 The fact that this Section becomes inoperative as set
12 forth in this subsection shall not be construed to mean that
13 the Commission may reexamine or otherwise reopen prudence or
14 reasonableness determinations already made.

15 (h) By December 31, 2017, the Commission shall prepare and
16 file with the General Assembly a report on the infrastructure
17 program and the performance-based formula rate. The report
18 shall include the change in the average amount per
19 kilowatthour paid by residential customers between June 1,
20 2011 and May 31, 2017. If the change in the total average rate
21 paid exceeds 2.5% compounded annually, the Commission shall
22 include in the report an analysis that shows the portion of the
23 change due to the delivery services component and the portion
24 of the change due to the supply component of the rate. The
25 report shall include separate sections for each participating
26 utility.

1 This Section, other than this subsection (h), and Sections
2 ~~16-108.5,~~ 16-108.6, 16-108.7, and 16-108.8 of this Act, ~~other~~
3 ~~than this subsection (h),~~ are inoperative after December 31,
4 2022 for every participating utility other than a combination
5 utility, after which time a participating utility other than a
6 combination utility shall no longer be eligible to annually
7 update the performance-based formula rate tariff pursuant to
8 subsection (d) of this Section. At such time, the then current
9 rates shall remain in effect until such time as new rates are
10 set pursuant to Article IX of this Act, subject to retroactive
11 adjustment, with interest, to reconcile rates charged with
12 actual costs.

13 This Section, other than this subsection (h), and Sections
14 16-108.6, 16-108.7, and 16-108.8 of this Act are inoperative
15 after December 31, 2032 for every participating utility that
16 is a combination utility, after which time a participating
17 utility that is a combination utility shall no longer be
18 eligible to annually update the performance-based formula rate
19 tariff pursuant to subsection (d) of this Section. At such
20 time, the then current rates shall remain in effect until such
21 time as new rates are set pursuant to Article IX of this Act,
22 subject to retroactive adjustment, with interest, to reconcile
23 rates charged with actual costs.

24 The fact that this Section becomes inoperative as set
25 forth in this subsection shall not be construed to mean that
26 the Commission may reexamine or otherwise reopen prudence or

1 reasonableness determinations already made.

2 (i) While a participating utility may use, develop, and
3 maintain broadband systems and the delivery of broadband
4 services, voice-over-internet-protocol services,
5 telecommunications services, and cable and video programming
6 services for use in providing delivery services and Smart Grid
7 functionality or application to its retail customers,
8 including, but not limited to, the installation,
9 implementation and maintenance of Smart Grid electric system
10 upgrades as defined in Section 16-108.6 of this Act, a
11 participating utility is prohibited from offering to its
12 retail customers broadband services or the delivery of
13 broadband services, voice-over-internet-protocol services,
14 telecommunications services, or cable or video programming
15 services, unless they are part of a service directly related
16 to delivery services or Smart Grid functionality or
17 applications as defined in Section 16-108.6 of this Act, and
18 from recovering the costs of such offerings from retail
19 customers.

20 (j) Nothing in this Section is intended to legislatively
21 overturn the opinion issued in Commonwealth Edison Co. v. Ill.
22 Commerce Comm'n, Nos. 2-08-0959, 2-08-1037, 2-08-1137,
23 1-08-3008, 1-08-3030, 1-08-3054, 1-08-3313 cons. (Ill. App.
24 Ct. 2d Dist. Sept. 30, 2010). Public Act 97-616 shall not be
25 construed as creating a contract between the General Assembly
26 and the participating utility, and shall not establish a

1 property right in the participating utility.

2 (k) The changes made in subsections (c) and (d) of this
3 Section by Public Act 98-15 are intended to be a restatement
4 and clarification of existing law, and intended to give
5 binding effect to the provisions of House Resolution 1157
6 adopted by the House of Representatives of the 97th General
7 Assembly and Senate Resolution 821 adopted by the Senate of
8 the 97th General Assembly that are reflected in paragraph (3)
9 of this subsection. In addition, Public Act 98-15 preempts and
10 supersedes any final Commission orders entered in Docket Nos.
11 11-0721, 12-0001, 12-0293, and 12-0321 to the extent
12 inconsistent with the amendatory language added to subsections
13 (c) and (d).

14 (1) No earlier than 5 business days after May 22, 2013
15 (the effective date of Public Act 98-15), each
16 participating utility shall file any tariff changes
17 necessary to implement the amendatory language set forth
18 in subsections (c) and (d) of this Section by Public Act
19 98-15 and a revised revenue requirement under the
20 participating utility's performance-based formula rate.
21 The Commission shall enter a final order approving such
22 tariff changes and revised revenue requirement within 21
23 days after the participating utility's filing.

24 (2) Notwithstanding anything that may be to the
25 contrary, a participating utility may file a tariff to
26 retroactively recover its previously unrecovered actual

1 costs of delivery service that are no longer subject to
2 recovery through a reconciliation adjustment under
3 subsection (d) of this Section. This retroactive recovery
4 shall include any derivative adjustments resulting from
5 the changes to subsections (c) and (d) of this Section by
6 Public Act 98-15. Such tariff shall allow the utility to
7 assess, on current customer bills over a period of 12
8 monthly billing periods, a charge or credit related to
9 those unrecovered costs with interest at the utility's
10 weighted average cost of capital during the period in
11 which those costs were unrecovered. A participating
12 utility may file a tariff that implements a retroactive
13 charge or credit as described in this paragraph for
14 amounts not otherwise included in the tariff filing
15 provided for in paragraph (1) of this subsection (k). The
16 Commission shall enter a final order approving such tariff
17 within 21 days after the participating utility's filing.

18 (3) The tariff changes described in paragraphs (1) and
19 (2) of this subsection (k) shall relate only to, and be
20 consistent with, the following provisions of Public Act
21 98-15: paragraph (2) of subsection (c) regarding year-end
22 capital structure, subparagraph (D) of paragraph (4) of
23 subsection (c) regarding pension assets, and subsection
24 (d) regarding the reconciliation components related to
25 year-end rate base and interest calculated at a rate equal
26 to the utility's weighted average cost of capital.

1 (4) Nothing in this subsection is intended to effect a
2 dismissal of or otherwise affect an appeal from any final
3 Commission orders entered in Docket Nos. 11-0721, 12-0001,
4 12-0293, and 12-0321 other than to the extent of the
5 amendatory language contained in subsections (c) and (d)
6 of this Section of Public Act 98-15.

7 (1) Each participating utility shall be deemed to have
8 been in full compliance with all requirements of subsection
9 (b) of this Section, subsection (c) of this Section, Section
10 16-108.6 of this Act, and all Commission orders entered
11 pursuant to Sections 16-108.5 and 16-108.6 of this Act, up to
12 and including May 22, 2013 (the effective date of Public Act
13 98-15). The Commission shall not undertake any investigation
14 of such compliance and no penalty shall be assessed or adverse
15 action taken against a participating utility for noncompliance
16 with Commission orders associated with subsection (b) of this
17 Section, subsection (c) of this Section, and Section 16-108.6
18 of this Act prior to such date. Each participating utility
19 other than a combination utility shall be permitted, without
20 penalty, a period of 12 months after such effective date to
21 take actions required to ensure its infrastructure investment
22 program is in compliance with subsection (b) of this Section
23 and with Section 16-108.6 of this Act. Provided further, the
24 following subparagraphs shall apply to a participating utility
25 other than a combination utility:

26 (A) if the Commission has initiated a proceeding

1 pursuant to subsection (e) of Section 16-108.6 of this Act
2 that is pending as of May 22, 2013 (the effective date of
3 Public Act 98-15), then the order entered in such
4 proceeding shall, after notice and hearing, accelerate the
5 commencement of the meter deployment schedule approved in
6 the final Commission order on rehearing entered in Docket
7 No. 12-0298;

8 (B) if the Commission has entered an order pursuant to
9 subsection (e) of Section 16-108.6 of this Act prior to
10 May 22, 2013 (the effective date of Public Act 98-15) that
11 does not accelerate the commencement of the meter
12 deployment schedule approved in the final Commission order
13 on rehearing entered in Docket No. 12-0298, then the
14 utility shall file with the Commission, within 45 days
15 after such effective date, a plan for accelerating the
16 commencement of the utility's meter deployment schedule
17 approved in the final Commission order on rehearing
18 entered in Docket No. 12-0298; the Commission shall reopen
19 the proceeding in which it entered its order pursuant to
20 subsection (e) of Section 16-108.6 of this Act and shall,
21 after notice and hearing, enter an amendatory order that
22 approves or approves as modified such accelerated plan
23 within 90 days after the utility's filing; or

24 (C) if the Commission has not initiated a proceeding
25 pursuant to subsection (e) of Section 16-108.6 of this Act
26 prior to May 22, 2013 (the effective date of Public Act

1 98-15), then the utility shall file with the Commission,
2 within 45 days after such effective date, a plan for
3 accelerating the commencement of the utility's meter
4 deployment schedule approved in the final Commission order
5 on rehearing entered in Docket No. 12-0298 and the
6 Commission shall, after notice and hearing, approve or
7 approve as modified such plan within 90 days after the
8 utility's filing.

9 Any schedule for meter deployment approved by the
10 Commission pursuant to this subsection (l) shall take into
11 consideration procurement times for meters and other equipment
12 and operational issues. Nothing in Public Act 98-15 shall
13 shorten or extend the end dates for the 5-year or 10-year
14 periods set forth in subsection (b) of this Section or Section
15 16-108.6 of this Act. Nothing in this subsection is intended
16 to address whether a participating utility has, or has not,
17 satisfied any or all of the metrics and performance goals
18 established pursuant to subsection (f) of this Section.

19 (m) The provisions of Public Act 98-15 are severable under
20 Section 1.31 of the Statute on Statutes.

21 (Source: P.A. 99-143, eff. 7-27-15; 99-642, eff. 7-28-16;
22 99-906, eff. 6-1-17; 100-840, eff. 8-13-18.)

23 (220 ILCS 5/16-108.19 new)

24 Sec. 16-108.19. Electric vehicle charging station
25 infrastructure.

1 (a) Notwithstanding any other provisions of this Act and
2 without obtaining any approvals from the Commission or any
3 other agency, including, but not limited to, approvals
4 otherwise required under Section 8-406 of this Act, regardless
5 of whether any such approval would otherwise be required,
6 electric utilities that serve less than 3,000,000 retail
7 customers but more than 500,000 retail customers in this State
8 are authorized to, but are not required to, plan for,
9 construct, install, control, own, manage, or operate electric
10 vehicle charging infrastructure, including, but not limited
11 to, electric vehicle charging stations within their service
12 territories. Electric utilities that serve less than 3,000,000
13 retail customers but more than 500,000 retail customers in
14 this State may construct electric vehicle charging
15 infrastructure on private property or publicly owned property;
16 however, the Commission may not authorize an electric utility
17 under Section 8-509 of this Act to acquire property rights by
18 eminent domain for the construction of any electric vehicle
19 charging station. Electric utilities that serve less than
20 3,000,000 retail customers but more than 500,000 retail
21 customers in this State shall be allowed to recover all
22 reasonable and prudent costs associated with investment in the
23 electric vehicle charging infrastructure, including, but not
24 limited to, costs to plan for, construct, install, control,
25 own, manage, or operate under this Section through the
26 applicable provisions of this Article XVI or Article IX of

1 this Act.

2 (b) Electric utilities that serve less than 3,000,000
3 retail customers but more than 500,000 retail customers in
4 this State may file with the Commission an electric vehicle
5 charging infrastructure deployment and charging facility
6 rebate plan, the purpose of which shall be to encourage the
7 adoption of electric vehicles in this State, including in the
8 service territory of the electric utilities subject to this
9 Section. The plan filed by an electric utility subject to this
10 Section shall identify a system of publicly accessible
11 electric vehicle charging stations and a schedule of rebates
12 that would be available to: (1) retail customers taking
13 electric service from the electric utility at an address in
14 the electric utility's service territory; and (2) any third
15 party that would construct, own, or operate a publicly
16 accessible electric vehicle charging station as authorized by
17 this Section. The Commission shall review the plan for
18 compliance with the provisions of this Section 16-108.19 and
19 issue an order either approving or modifying the plan within
20 180 days after the initial filing. If the Commission finds
21 that the plan filed pursuant to this subsection (b) complies
22 with the requirements of subsections (c) and (d) of this
23 Section, the Commission shall approve the plan and the
24 electric utility shall implement it in accordance with the
25 Commission approval. If the Commission modifies the plan, the
26 electric utility shall notify the Commission in writing within

1 90 days after service of the Commission's order modifying the
2 plan as to whether the electric utility accepts the
3 Commission's modifications. If the electric utility notifies
4 the Commission in writing that it does not accept the
5 Commission's modifications, the electric utility shall have no
6 further obligations with respect to the plan, including any
7 obligation to implement the plan as modified and may, at its
8 discretion, file a new plan with the Commission in the future.
9 Upon approval by the Commission and acceptance by the electric
10 utility of a plan filed under this subsection (b), no further
11 approvals by the Commission other than those approvals set
12 forth in this Section shall be necessary and the electric
13 utility shall implement the approved plan in accordance with
14 the Commission's approval.

15 (c) A plan filed under subsection (b) of this Section
16 shall include, at a minimum, the following categories of
17 information regarding the proposed deployment of electric
18 vehicle charging stations:

19 (1) Identification of existing publicly accessible
20 electric vehicle charging station infrastructure installed
21 in the electric utility's service territory.

22 (2) Sufficient detail to identify the proposed general
23 location and type of electric vehicle charging station
24 infrastructure that could be installed on private or
25 publicly owned land along proposed electric vehicle
26 charging corridors or other public spaces within the

1 electric utility's service territory, including the
2 general identification of any proposed location and type
3 of electric vehicle charging station infrastructure that
4 the electric utility proposes to be part of the
5 third-party request for proposals process set forth in
6 paragraph (3) of this subsection (c);

7 (3) A proposed request for proposals process to be
8 managed by the electric utility, which shall request
9 proposals from third parties to compete for utility
10 rebates for the construction, ownership, and operation of
11 the electric vehicle charging stations within the electric
12 utility's service territory. The request for proposals
13 process shall address at least the following information
14 for the proposed electric vehicle charging infrastructure:

15 (A) requirements for electric vehicle charging
16 station infrastructure owners and operators regarding
17 construction, installation, operation, and maintenance
18 for each proposed general location;

19 (B) criteria by which the bids will be reviewed
20 and assessed; however, bids shall address the proposed
21 ownership and ongoing operation of the electric
22 vehicle charging station and the bids may be
23 contingent on securing State or federal funds,
24 including any tax incentives, available for electric
25 vehicle charging station development or deployment;

26 (C) provisions for how rebates will be made

1 available to electric vehicle charging station winning
2 bidders, which shall be designed to encourage
3 participation in the request for proposals process and
4 actual construction, installation, ownership, and
5 operation of the electric vehicle charging station at
6 each proposed location; and

7 (D) a proposal that provides the electric utility
8 the option to plan for, construct, install, control,
9 own, manage, or operate any electric vehicle charging
10 infrastructure at any location identified for
11 inclusion in the request for proposals, but for which
12 no third-party bid was received or awarded under the
13 criteria identified pursuant to this paragraph (3).

14 (d) In addition to the information set forth in subsection
15 (c) of this Section, a plan filed under subsection (b) of this
16 Section shall also include the following categories of
17 information:

18 (1) The proposed rebates offered by the electric
19 utility to customers taking service from the electric
20 utility at an address within its service territory for
21 electric vehicle charging infrastructure or facilities,
22 which should include, but not be limited to, the following
23 information:

24 (A) identification of available rebates for
25 electric utility residential customers who purchase
26 electric vehicles and install home electric vehicle

1 charging facilities subsequent to the effective date
2 of this amendatory Act of the 102nd General Assembly;

3 (B) identification of available rebates for
4 multi-family residential buildings and non-residential
5 customers that, subsequent to the effective date of
6 this amendatory Act of the 102nd General Assembly,
7 install and provide access to electric vehicle
8 charging facilities located in a common area generally
9 available to residents or the public;

10 (C) identification of available rebates designed
11 to promote the use of electric vehicles serving
12 low-income or moderate-income communities, including,
13 but not limited to, any rebates available to shared
14 electric vehicles, ride share electric vehicles, and
15 public transportation fleets or school districts using
16 electric vehicles; and

17 (D) the manner and timing of the payment of the
18 proposed rebates; however, the rebates identified
19 pursuant to this paragraph (1) may be paid through a
20 monthly bill credit spread fairly and reasonably
21 across a 12-month period, and provided any customer
22 receiving a rebate must sign up for and remain on a
23 3-part delivery service rate, if available.

24 (2) An estimated budget for the electric utility to
25 develop and implement an education and engagement strategy
26 that encourages the adoption of electric vehicles in the

1 electric utility's service territory, including, but not
2 limited to, programs to be delivered to entities that
3 educate and promote the adoption of electric vehicles,
4 including, but not limited to, car dealerships and
5 elementary, middle, and high schools.

6 (e) An electric utility implementing a plan approved
7 pursuant to subsection (b) of this Section, may update its
8 plan at any time by filing such update with the Commission in
9 the same docket in which the Commission originally approved
10 the plan. Any updated filing made pursuant to this subsection
11 (e) must identify the updates to be implemented and any
12 updates shall be deemed approved as reasonable 45 days after
13 the filing unless the Commission initiates an investigation
14 into the updated actions. Any final order regarding the
15 investigation initiated pursuant to this subsection (e) must
16 be issued within 180 days of the initiating order.

17 (f) Notwithstanding any other provision of law to the
18 contrary, electric utilities that serve less than 3,000,000
19 retail customers but more than 500,000 retail customers in
20 this State shall be permitted to recover all reasonable and
21 prudently incurred costs incurred under this Section,
22 including, but not limited to, any costs incurred to make any
23 location identified pursuant to subsections (b) and (c) of
24 this Section ready for installation and connection of an
25 electric vehicle charging station to the distribution system;
26 the costs incurred to provide the rebates identified pursuant

1 to subsections (b), (c), and (d) of this Section; the costs
2 incurred to undertake the education and engagement activities
3 authorized under this Section; and other costs incurred by the
4 utility to comply with and implement the requirements of this
5 Section, including any amounts that reasonably exceed any
6 estimates provided as part of the plan filed pursuant to
7 subsection (b) of this Section. Electric utilities that serve
8 less than 3,000,000 retail customers but more than 500,000
9 retail customers in this State are authorized to recover any
10 costs identified in this subsection (f) by way of a tariff or
11 tariffs approved by the Illinois Commerce Commission,
12 consistent with the following provisions:

13 (1) An electric utility subject to this Section shall
14 be permitted to recover all reasonable and prudently
15 incurred costs incurred to make any location identified
16 pursuant to subsections (b) and (c) of this Section ready
17 for installation and connection of an electric vehicle
18 charging station to the distribution system through its
19 delivery service rates, as authorized by the applicable
20 provisions of Article IX or this Article XVI. For any
21 electric vehicle infrastructure identified in any plan
22 filed pursuant to subsections (b) and (c) of this Section,
23 distribution extension free allowances up to and including
24 \$1,500 per kilowatt of connected electric vehicle charging
25 station equipment shall be deemed reasonable and shall not
26 limit the use of alternate extension provisions

1 demonstrated to be more favorable and approved by the
2 Illinois Commerce Commission.

3 (2) Beginning on the effective date of this amendatory
4 Act of the 102nd General Assembly, an electric utility
5 subject to this Section shall have authority to defer up
6 to the full amount of its costs incurred under this
7 Section, other than those costs being recovered pursuant
8 to paragraph (1) of this subsection (f), as a regulatory
9 asset, to be amortized over a 15-year period. The
10 unamortized balance shall be recognized as of December 31
11 for a given year. The utility shall also earn a return on
12 the total of the unamortized balance of the regulatory
13 asset authorized under this Section, less any deferred
14 taxes related to the unamortized balance, at an annual
15 rate equal to the utility's weighted average cost of
16 capital that includes, based on a year-end capital
17 structure, the utility's actual cost of debt for the
18 applicable calendar year and a cost of equity, which shall
19 be equal to the national average cost of equity as
20 calculated under this paragraph (2). For purposes of this
21 paragraph (2), the national average cost of equity for a
22 calendar year shall be the simple average of the cost of
23 equity specified and approved in each order of a state
24 regulatory commission, other than the Commission, issued
25 during such calendar year that is applicable to base rates
26 for retail electric service provided by an investor-owned

1 public utility company operating in the United States. No
2 order shall be excluded from the national average cost of
3 equity calculated under this paragraph (2) on the grounds
4 that it was arrived at by stipulation or agreement or is
5 subject to rehearing or appeal. If, for any calendar year,
6 there are fewer than 15 applicable orders of state
7 regulatory commissions with which to compute the average
8 cost of equity, the Commission shall include in the
9 calculation of the national average the number of state
10 regulatory orders from the year or years immediately
11 preceding such calendar year necessary to reach a total of
12 15, beginning with the most recently issued and proceeding
13 in reverse chronological order.

14 (3) When an electric utility subject to this Section
15 creates a regulatory asset under the provisions of this
16 Section, the costs shall be recovered over a period during
17 which customers also receive a benefit, which is in the
18 public interest. Accordingly, it is the intent of the
19 General Assembly that an electric utility that elects to
20 create a regulatory asset under the provisions of this
21 Section shall recover all of the associated costs,
22 including, but not limited to, its cost of capital as set
23 forth in this Section. After the Commission has approved,
24 as set forth in this Section, the prudence and
25 reasonableness of the costs that comprise the regulatory
26 asset, the electric utility shall be permitted to recover

1 all such costs, and the value and recoverability through
2 rates of the associated regulatory asset shall not be
3 limited, altered, impaired, or reduced. To enable the
4 financing of the incremental capital expenditures,
5 including regulatory assets, for electric utilities
6 subject to this Section, the utility's actual year-end
7 capital structure that includes a common equity ratio,
8 excluding goodwill, of up to and including 54% of the
9 total capital structure shall be deemed reasonable and
10 used to set rates.

11 (4) Notwithstanding paragraph (1) of this subsection
12 (f), an electric utility subject to this Section may, at
13 its election, recover some or all of the costs it incurs
14 under this Section as part of a filing for a general
15 increase in rates under Article IX of this Act, as part of
16 an annual filing to update a performance-based formula
17 rate under subsection (d) of Section 16-108.5 of this Act
18 or subsection (d) of Section 8-103B, or through an
19 automatic adjustment clause tariff; provided that nothing
20 in this paragraph (4) of this subsection (f) permits the
21 double recovery of such costs from customers. Such costs
22 shall be allocated across all classes of retail customers
23 in proportion to delivery service revenue requirement
24 attributed to a class. If the electric utility elects to
25 recover the costs it incurs under this Section through an
26 automatic adjustment clause tariff, the utility may file

1 its proposed tariff together with the plan it files under
2 subsection (b) of this Section or at a later time. The
3 proposed tariff shall provide for an annual
4 reconciliation, less any deferred taxes related to the
5 reconciliation, with interest at an annual rate of return
6 equal to the utility's weighted average cost of capital as
7 calculated under paragraph (2) of this subsection (f),
8 including a revenue conversion factor calculated to
9 recover or refund all additional income taxes that may be
10 payable or receivable as a result of that return, of the
11 revenue requirement reflected in rates for each calendar
12 year, beginning with the calendar year in which the
13 utility files its automatic adjustment clause tariff under
14 this subsection (f), with what the revenue requirement
15 would have been had the actual cost information for the
16 applicable calendar year been available at the filing
17 date. The tariff may permit recovery of costs through a
18 single cents per kilowatt-hour charge applicable to each
19 retail class. The Commission shall review the proposed
20 tariff and may make changes to the tariff that are
21 consistent with this Section and with the Commission's
22 authority under Article IX of this Act, subject to notice
23 and hearing, as required. Following notice and hearing, as
24 required, the Commission shall issue an order approving,
25 or approving with modification, such tariff no later than
26 240 days after the electric utility files its tariff.

1 (g) Any electric vehicle charging infrastructure,
2 including, but not limited to, an electric vehicle charging
3 station, constructed, installed, controlled, owned, managed,
4 or operated by an electric utility pursuant to this Section
5 shall be treated as jurisdictional distribution plant assets
6 for ratemaking purposes. The investment in, and the costs to
7 construct, install, control, own, manage, or operate electric
8 vehicle charging infrastructure owned by the electric utility
9 shall be fully recovered in delivery service rates. The
10 electric utility shall charge, pursuant to a tariff on file
11 with the Commission, market rates for electricity sold through
12 every such electric vehicle charging station, and all revenue
13 from such sales shall be credited to distribution customers in
14 the applicable ratemaking process.

15 (h) In addition to the plan authorized in subsection (b),
16 electric utilities that serve less than 3,000,000 retail
17 customers but more than 500,000 retail customers in this State
18 shall be permitted to administer programs designed to
19 encourage or incentivize the adoption of electric vehicles by
20 Illinois electric consumers, and such programs shall not be
21 prohibited by the Commission as promotional practices under
22 any rules or policies of the Commission, including, but not
23 limited to, 83 Ill. Adm. Code Part 275.

24 (220 ILCS 5/16-108.20 new)

25 Sec. 16-108.20. Electric energy storage.

1 (a) An electric utility may plan for, construct, install,
2 control, own, manage, or operate energy storage as part of its
3 distribution system when such electric utility has reasonably
4 and prudently assessed and determined that such energy storage
5 will preserve, maintain, or improve stability and reliability
6 of the electric utility's distribution system.

7 (b) Notwithstanding any other provision of law to the
8 contrary, an electric utility subject to this Section shall be
9 permitted to recover all reasonable and prudently incurred
10 costs incurred under this Section, including, but not limited
11 to, the costs incurred to plan for, construct, control, own,
12 manage, or operate the infrastructure and undertake activities
13 identified in this Section in a reasonable and prudent manner
14 pursuant to Article IX or this Article XVI, as applicable, and
15 for purposes of cost recovery the energy storage facilities
16 shall be treated as distribution assets; provided that: (1)
17 the Commission shall have the authority to determine the
18 reasonableness of the costs of the facilities; and (2) any
19 monetary value of power and energy from the facilities shall
20 be credited against the delivery services revenue requirement.
21 An electric utility subject to this Section shall operate
22 storage for the primary purpose of facilitating stable and
23 reliable delivery service, and any loss incidental to the
24 operation of storage facilities shall also be recoverable to
25 the extent such losses were prudently incurred as a result of
26 the operation of the facility.

1 (220 ILCS 5/16-111.5)

2 Sec. 16-111.5. Provisions relating to procurement.

3 (a) An electric utility that on December 31, 2005 served
4 at least 100,000 customers in Illinois shall procure power and
5 energy for its eligible retail customers in accordance with
6 the applicable provisions set forth in Section 1-75 of the
7 Illinois Power Agency Act and this Section. Beginning with the
8 delivery year commencing on June 1, 2017, such electric
9 utility shall also procure zero emission credits from zero
10 emission facilities in accordance with the applicable
11 provisions set forth in Section 1-75 of the Illinois Power
12 Agency Act, and, for years beginning on or after June 1, 2017,
13 the utility shall procure renewable energy resources in
14 accordance with the applicable provisions set forth in Section
15 1-75 of the Illinois Power Agency Act and this Section. A small
16 multi-jurisdictional electric utility that on December 31,
17 2005 served less than 100,000 customers in Illinois may elect
18 to procure power and energy for all or a portion of its
19 eligible Illinois retail customers in accordance with the
20 applicable provisions set forth in this Section and Section
21 1-75 of the Illinois Power Agency Act. This Section shall not
22 apply to a small multi-jurisdictional utility until such time
23 as a small multi-jurisdictional utility requests the Illinois
24 Power Agency to prepare a procurement plan for its eligible
25 retail customers. "Eligible retail customers" for the purposes

1 of this Section means those retail customers that purchase
2 power and energy from the electric utility under fixed-price
3 bundled service tariffs, other than those retail customers
4 whose service is declared or deemed competitive under Section
5 16-113 and those other customer groups specified in this
6 Section, including self-generating customers, customers
7 electing hourly pricing, or those customers who are otherwise
8 ineligible for fixed-price bundled tariff service. For those
9 customers that are excluded from the procurement plan's
10 electric supply service requirements, and the utility shall
11 procure any supply requirements, including capacity, ancillary
12 services, and hourly priced energy, in the applicable markets
13 as needed to serve those customers, provided that the utility
14 may include in its procurement plan load requirements for the
15 load that is associated with those retail customers whose
16 service has been declared or deemed competitive pursuant to
17 Section 16-113 of this Act to the extent that those customers
18 are purchasing power and energy during one of the transition
19 periods identified in subsection (b) of Section 16-113 of this
20 Act.

21 (b) A procurement plan shall be prepared for each electric
22 utility consistent with the applicable requirements of the
23 Illinois Power Agency Act and this Section. For purposes of
24 this Section, Illinois electric utilities that are affiliated
25 by virtue of a common parent company are considered to be a
26 single electric utility. Small multi-jurisdictional utilities

1 may request a procurement plan for a portion of or all of its
2 Illinois load. Each procurement plan shall analyze the
3 projected balance of supply and demand for those retail
4 customers to be included in the plan's electric supply service
5 requirements over a 5-year period, with the first planning
6 year beginning on June 1 of the year following the year in
7 which the plan is filed. The plan shall specifically identify
8 the wholesale products to be procured following plan approval,
9 and shall follow all the requirements set forth in the Public
10 Utilities Act and all applicable State and federal laws,
11 statutes, rules, or regulations, as well as Commission orders.
12 Nothing in this Section precludes consideration of contracts
13 longer than 5 years and related forecast data. Unless
14 specified otherwise in this Section, in the procurement plan
15 or in the implementing tariff, any procurement occurring in
16 accordance with this plan shall be competitively bid through a
17 request for proposals process. Approval and implementation of
18 the procurement plan shall be subject to review and approval
19 by the Commission according to the provisions set forth in
20 this Section. A procurement plan shall include each of the
21 following components:

22 (1) Hourly load analysis. This analysis shall include:

23 (i) multi-year historical analysis of hourly
24 loads;

25 (ii) switching trends and competitive retail
26 market analysis;

1 (iii) known or projected changes to future loads;

2 and

3 (iv) growth forecasts by customer class.

4 (2) Analysis of the impact of any demand side and
5 renewable energy initiatives. This analysis shall include:

6 (i) the impact of demand response programs and
7 energy efficiency programs, both current and
8 projected; for small multi-jurisdictional utilities,
9 the impact of demand response and energy efficiency
10 programs approved pursuant to Section 8-408 of this
11 Act, both current and projected; and

12 (ii) supply side needs that are projected to be
13 offset by purchases of renewable energy resources, if
14 any.

15 (3) A plan for meeting the expected load requirements
16 that will not be met through preexisting contracts. This
17 plan shall include:

18 (i) definitions of the different Illinois retail
19 customer classes for which supply is being purchased;

20 (ii) the proposed mix of demand-response products
21 for which contracts will be executed during the next
22 year. For small multi-jurisdictional electric
23 utilities that on December 31, 2005 served fewer than
24 100,000 customers in Illinois, these shall be defined
25 as demand-response products offered in an energy
26 efficiency plan approved pursuant to Section 8-408 of

1 this Act. The cost-effective demand-response measures
2 shall be procured whenever the cost is lower than
3 procuring comparable capacity products, provided that
4 such products shall:

5 (A) be procured by a demand-response provider
6 from those retail customers included in the plan's
7 electric supply service requirements;

8 (B) at least satisfy the demand-response
9 requirements of the regional transmission
10 organization market in which the utility's service
11 territory is located, including, but not limited
12 to, any applicable capacity or dispatch
13 requirements;

14 (C) provide for customers' participation in
15 the stream of benefits produced by the
16 demand-response products;

17 (D) provide for reimbursement by the
18 demand-response provider of the utility for any
19 costs incurred as a result of the failure of the
20 supplier of such products to perform its
21 obligations thereunder; and

22 (E) meet the same credit requirements as apply
23 to suppliers of capacity, in the applicable
24 regional transmission organization market;

25 (iii) monthly forecasted system supply
26 requirements, including expected minimum, maximum, and

1 average values for the planning period;

2 (iv) the proposed mix and selection of standard
3 wholesale products for which contracts will be
4 executed during the next year, separately or in
5 combination, to meet that portion of its load
6 requirements not met through pre-existing contracts,
7 including but not limited to monthly 5 x 16 peak period
8 block energy, monthly off-peak wrap energy, monthly 7
9 x 24 energy, annual 5 x 16 energy, annual off-peak wrap
10 energy, annual 7 x 24 energy, monthly capacity, annual
11 capacity, peak load capacity obligations, capacity
12 purchase plan, and ancillary services;

13 (v) proposed term structures for each wholesale
14 product type included in the proposed procurement plan
15 portfolio of products; and

16 (vi) an assessment of the price risk, load
17 uncertainty, and other factors that are associated
18 with the proposed procurement plan; this assessment,
19 to the extent possible, shall include an analysis of
20 the following factors: contract terms, time frames for
21 securing products or services, fuel costs, weather
22 patterns, transmission costs, market conditions, and
23 the governmental regulatory environment; the proposed
24 procurement plan shall also identify alternatives for
25 those portfolio measures that are identified as having
26 significant price risk.

1 (4) Proposed procedures for balancing loads. The
2 procurement plan shall include, for load requirements
3 included in the procurement plan, the process for (i)
4 hourly balancing of supply and demand and (ii) the
5 criteria for portfolio re-balancing in the event of
6 significant shifts in load.

7 (5) Long-Term Renewable Resources Procurement Plan.
8 The Agency shall prepare a long-term renewable resources
9 procurement plan for the procurement of renewable energy
10 credits under Sections 1-56 and 1-75 of the Illinois Power
11 Agency Act for delivery beginning in the 2017 delivery
12 year.

13 (i) The initial long-term renewable resources
14 procurement plan and all subsequent revisions shall be
15 subject to review and approval by the Commission. For
16 the purposes of this Section, "delivery year" has the
17 same meaning as in Section 1-10 of the Illinois Power
18 Agency Act. For purposes of this Section, "Agency"
19 shall mean the Illinois Power Agency.

20 (ii) The long-term renewable resources planning
21 process shall be conducted as follows:

22 (A) Electric utilities shall provide a range
23 of load forecasts to the Illinois Power Agency
24 within 45 days of the Agency's request for
25 forecasts, which request shall specify the length
26 and conditions for the forecasts including, but

1 not limited to, the quantity of distributed
2 generation expected to be interconnected for each
3 year.

4 (B) The Agency shall publish for comment the
5 initial long-term renewable resources procurement
6 plan no later than 120 days after the effective
7 date of this amendatory Act of the 99th General
8 Assembly and shall review, and may revise, the
9 plan at least every 2 years thereafter. To the
10 extent practicable, the Agency shall review and
11 propose any revisions to the long-term renewable
12 energy resources procurement plan in conjunction
13 with the Agency's other planning and approval
14 processes conducted under this Section. The
15 initial long-term renewable resources procurement
16 plan shall:

17 (aa) Identify the procurement programs and
18 competitive procurement events consistent with
19 the applicable requirements of the Illinois
20 Power Agency Act and shall be designed to
21 achieve the goals set forth in subsection (c)
22 of Section 1-75 of that Act.

23 (bb) Include a schedule for procurements
24 for renewable energy credits from
25 utility-scale wind projects, utility-scale
26 solar projects, and brownfield site

1 photovoltaic projects consistent with
2 subparagraph (G) of paragraph (1) of
3 subsection (c) of Section 1-75 of the Illinois
4 Power Agency Act.

5 (cc) Identify the process whereby the
6 Agency will submit to the Commission for
7 review and approval the proposed contracts to
8 implement the programs required by such plan.

9 Copies of the initial long-term renewable
10 resources procurement plan and all subsequent
11 revisions shall be posted and made publicly
12 available on the Agency's and Commission's
13 websites, and copies shall also be provided to
14 each affected electric utility. As part of any
15 renewable resources procurement plan, the Agency
16 will compile and publish a list of any sellers of
17 renewable energy resources procured by the Agency
18 that are not, as of January 1 of the calendar year
19 in which the procurement plan will be filed for
20 approval with the Commission, in compliance with
21 the reporting obligations of Section 5-117 of the
22 Public Utilities Act, and the Agency shall not
23 procure any renewable energy resources from any
24 entity not in compliance with the reporting
25 obligations of Section 5-117 of the Public
26 Utilities Act in the procurement plan. An affected

1 utility and other interested parties shall have 45
2 days following the date of posting to provide
3 comment to the Agency on the initial long-term
4 renewable resources procurement plan and all
5 subsequent revisions. All comments submitted to
6 the Agency shall be specific, supported by data or
7 other detailed analyses, and, if objecting to all
8 or a portion of the procurement plan, accompanied
9 by specific alternative wording or proposals. All
10 comments shall be posted on the Agency's and
11 Commission's websites. During this 45-day comment
12 period, the Agency shall hold at least one public
13 hearing within each utility's service area that is
14 subject to the requirements of this paragraph (5)
15 for the purpose of receiving public comment.
16 Within 21 days following the end of the 45-day
17 review period, the Agency may revise the long-term
18 renewable resources procurement plan based on the
19 comments received and shall file the plan with the
20 Commission for review and approval.

21 (C) Within 14 days after the filing of the
22 initial long-term renewable resources procurement
23 plan or any subsequent revisions, any person
24 objecting to the plan may file an objection with
25 the Commission. Within 21 days after the filing of
26 the plan, the Commission shall determine whether a

1 hearing is necessary. The Commission shall enter
2 its order confirming or modifying the initial
3 long-term renewable resources procurement plan or
4 any subsequent revisions within 120 days after the
5 filing of the plan by the Illinois Power Agency.

6 (D) The Commission shall approve the initial
7 long-term renewable resources procurement plan and
8 any subsequent revisions, including expressly the
9 forecast used in the plan and taking into account
10 that funding will be limited to the amount of
11 revenues actually collected by the utilities, if
12 the Commission determines that the plan will
13 reasonably and prudently accomplish the
14 requirements of Section 1-56 and subsection (c) of
15 Section 1-75 of the Illinois Power Agency Act. The
16 Commission shall also approve the process for the
17 submission, review, and approval of the proposed
18 contracts to procure renewable energy credits or
19 implement the programs authorized by the
20 Commission pursuant to a long-term renewable
21 resources procurement plan approved under this
22 Section.

23 (iii) The Agency or third parties contracted by
24 the Agency shall implement all programs authorized by
25 the Commission in an approved long-term renewable
26 resources procurement plan without further review and

1 approval by the Commission. Third parties shall not
2 begin implementing any programs or receive any payment
3 under this Section until the Commission has approved
4 the contract or contracts under the process authorized
5 by the Commission in item (D) of subparagraph (ii) of
6 paragraph (5) of this subsection (b) and the third
7 party and the Agency or utility, as applicable, have
8 executed the contract. For those renewable energy
9 credits subject to procurement through a competitive
10 bid process under the plan or under the initial
11 forward procurements for wind and solar resources
12 described in subparagraph (G) of paragraph (1) of
13 subsection (c) of Section 1-75 of the Illinois Power
14 Agency Act, the Agency shall follow the procurement
15 process specified in the provisions relating to
16 electricity procurement in subsections (e) through (i)
17 of this Section.

18 (iv) An electric utility shall recover its costs
19 associated with the procurement of renewable energy
20 credits under this Section through an automatic
21 adjustment clause tariff under subsection (k) of
22 Section 16-108 of this Act. A utility shall not be
23 required to advance any payment or pay any amounts
24 under this Section that exceed the actual amount of
25 revenues collected by the utility under paragraph (6)
26 of subsection (c) of Section 1-75 of the Illinois

1 Power Agency Act and subsection (k) of Section 16-108
2 of this Act, and contracts executed under this Section
3 shall expressly incorporate this limitation.

4 (v) For the public interest, safety, and welfare,
5 the Agency and the Commission may adopt rules to carry
6 out the provisions of this Section on an emergency
7 basis immediately following the effective date of this
8 amendatory Act of the 99th General Assembly.

9 (vi) On or before July 1 of each year, the
10 Commission shall hold an informal hearing for the
11 purpose of receiving comments on the prior year's
12 procurement process and any recommendations for
13 change.

14 (c) The procurement process set forth in Section 1-75 of
15 the Illinois Power Agency Act and subsection (e) of this
16 Section shall be administered by a procurement administrator
17 and monitored by a procurement monitor.

18 (1) The procurement administrator shall:

19 (i) design the final procurement process in
20 accordance with Section 1-75 of the Illinois Power
21 Agency Act and subsection (e) of this Section
22 following Commission approval of the procurement plan;

23 (ii) develop benchmarks in accordance with
24 subsection (e)(3) to be used to evaluate bids; these
25 benchmarks shall be submitted to the Commission for
26 review and approval on a confidential basis prior to

1 the procurement event;

2 (iii) serve as the interface between the electric
3 utility and suppliers;

4 (iv) manage the bidder pre-qualification and
5 registration process;

6 (v) obtain the electric utilities' agreement to
7 the final form of all supply contracts and credit
8 collateral agreements;

9 (vi) administer the request for proposals process;

10 (vii) have the discretion to negotiate to
11 determine whether bidders are willing to lower the
12 price of bids that meet the benchmarks approved by the
13 Commission; any post-bid negotiations with bidders
14 shall be limited to price only and shall be completed
15 within 24 hours after opening the sealed bids and
16 shall be conducted in a fair and unbiased manner; in
17 conducting the negotiations, there shall be no
18 disclosure of any information derived from proposals
19 submitted by competing bidders; if information is
20 disclosed to any bidder, it shall be provided to all
21 competing bidders;

22 (viii) maintain confidentiality of supplier and
23 bidding information in a manner consistent with all
24 applicable laws, rules, regulations, and tariffs;

25 (ix) submit a confidential report to the
26 Commission recommending acceptance or rejection of

1 bids;

2 (x) notify the utility of contract counterparties
3 and contract specifics; and

4 (xi) administer related contingency procurement
5 events.

6 (2) The procurement monitor, who shall be retained by
7 the Commission, shall:

8 (i) monitor interactions among the procurement
9 administrator, suppliers, and utility;

10 (ii) monitor and report to the Commission on the
11 progress of the procurement process;

12 (iii) provide an independent confidential report
13 to the Commission regarding the results of the
14 procurement event;

15 (iv) assess compliance with the procurement plans
16 approved by the Commission for each utility that on
17 December 31, 2005 provided electric service to at
18 least 100,000 customers in Illinois and for each small
19 multi-jurisdictional utility that on December 31, 2005
20 served less than 100,000 customers in Illinois;

21 (v) preserve the confidentiality of supplier and
22 bidding information in a manner consistent with all
23 applicable laws, rules, regulations, and tariffs;

24 (vi) provide expert advice to the Commission and
25 consult with the procurement administrator regarding
26 issues related to procurement process design, rules,

1 protocols, and policy-related matters; and

2 (vii) consult with the procurement administrator
3 regarding the development and use of benchmark
4 criteria, standard form contracts, credit policies,
5 and bid documents.

6 (d) Except as provided in subsection (j), the planning
7 process shall be conducted as follows:

8 (1) Beginning in 2008, each Illinois utility procuring
9 power pursuant to this Section shall annually provide a
10 range of load forecasts to the Illinois Power Agency by
11 July 15 of each year, or such other date as may be required
12 by the Commission or Agency. The load forecasts shall
13 cover the 5-year procurement planning period for the next
14 procurement plan and shall include hourly data
15 representing a high-load, low-load, and expected-load
16 scenario for the load of those retail customers included
17 in the plan's electric supply service requirements. The
18 utility shall provide supporting data and assumptions for
19 each of the scenarios.

20 (2) Beginning in 2008, the Illinois Power Agency shall
21 prepare a procurement plan by August 15th of each year, or
22 such other date as may be required by the Commission. The
23 procurement plan shall identify the portfolio of
24 demand-response and power and energy products to be
25 procured. Cost-effective demand-response measures shall be
26 procured as set forth in item (iii) of subsection (b) of

1 this Section. Copies of the procurement plan shall be
2 posted and made publicly available on the Agency's and
3 Commission's websites, and copies shall also be provided
4 to each affected electric utility. An affected utility
5 shall have 30 days following the date of posting to
6 provide comment to the Agency on the procurement plan.
7 Other interested entities also may comment on the
8 procurement plan. All comments submitted to the Agency
9 shall be specific, supported by data or other detailed
10 analyses, and, if objecting to all or a portion of the
11 procurement plan, accompanied by specific alternative
12 wording or proposals. All comments shall be posted on the
13 Agency's and Commission's websites. During this 30-day
14 comment period, the Agency shall hold at least one public
15 hearing within each utility's service area for the purpose
16 of receiving public comment on the procurement plan.
17 Within 14 days following the end of the 30-day review
18 period, the Agency shall revise the procurement plan as
19 necessary based on the comments received and file the
20 procurement plan with the Commission and post the
21 procurement plan on the websites.

22 (3) Within 5 days after the filing of the procurement
23 plan, any person objecting to the procurement plan shall
24 file an objection with the Commission. Within 10 days
25 after the filing, the Commission shall determine whether a
26 hearing is necessary. The Commission shall enter its order

1 confirming or modifying the procurement plan within 90
2 days after the filing of the procurement plan by the
3 Illinois Power Agency.

4 (4) The Commission shall approve the procurement plan,
5 including expressly the forecast used in the procurement
6 plan, if the Commission determines that it will ensure
7 adequate, reliable, affordable, efficient, and
8 environmentally sustainable electric service at the lowest
9 total cost over time, taking into account any benefits of
10 price stability.

11 (e) The procurement process shall include each of the
12 following components:

13 (1) Solicitation, pre-qualification, and registration
14 of bidders. The procurement administrator shall
15 disseminate information to potential bidders to promote a
16 procurement event, notify potential bidders that the
17 procurement administrator may enter into a post-bid price
18 negotiation with bidders that meet the applicable
19 benchmarks, provide supply requirements, and otherwise
20 explain the competitive procurement process. In addition
21 to such other publication as the procurement administrator
22 determines is appropriate, this information shall be
23 posted on the Illinois Power Agency's and the Commission's
24 websites. The procurement administrator shall also
25 administer the prequalification process, including
26 evaluation of credit worthiness, compliance with

1 procurement rules, and agreement to the standard form
2 contract developed pursuant to paragraph (2) of this
3 subsection (e). The procurement administrator shall then
4 identify and register bidders to participate in the
5 procurement event.

6 (2) Standard contract forms and credit terms and
7 instruments. The procurement administrator, in
8 consultation with the utilities, the Commission, and other
9 interested parties and subject to Commission oversight,
10 shall develop and provide standard contract forms for the
11 supplier contracts that meet generally accepted industry
12 practices. Standard credit terms and instruments that meet
13 generally accepted industry practices shall be similarly
14 developed. The procurement administrator shall make
15 available to the Commission all written comments it
16 receives on the contract forms, credit terms, or
17 instruments. If the procurement administrator cannot reach
18 agreement with the applicable electric utility as to the
19 contract terms and conditions, the procurement
20 administrator must notify the Commission of any disputed
21 terms and the Commission shall resolve the dispute. The
22 terms of the contracts shall not be subject to negotiation
23 by winning bidders, and the bidders must agree to the
24 terms of the contract in advance so that winning bids are
25 selected solely on the basis of price.

26 (3) Establishment of a market-based price benchmark.

1 As part of the development of the procurement process, the
2 procurement administrator, in consultation with the
3 Commission staff, Agency staff, and the procurement
4 monitor, shall establish benchmarks for evaluating the
5 final prices in the contracts for each of the products
6 that will be procured through the procurement process. The
7 benchmarks shall be based on price data for similar
8 products for the same delivery period and same delivery
9 hub, or other delivery hubs after adjusting for that
10 difference. The price benchmarks may also be adjusted to
11 take into account differences between the information
12 reflected in the underlying data sources and the specific
13 products and procurement process being used to procure
14 power for the Illinois utilities. The benchmarks shall be
15 confidential but shall be provided to, and will be subject
16 to Commission review and approval, prior to a procurement
17 event.

18 (4) Request for proposals competitive procurement
19 process. The procurement administrator shall design and
20 issue a request for proposals to supply electricity in
21 accordance with each utility's procurement plan, as
22 approved by the Commission. The request for proposals
23 shall set forth a procedure for sealed, binding commitment
24 bidding with pay-as-bid settlement, and provision for
25 selection of bids on the basis of price.

26 (5) A plan for implementing contingencies in the event

1 of supplier default or failure of the procurement process
2 to fully meet the expected load requirement due to
3 insufficient supplier participation, Commission rejection
4 of results, or any other cause.

5 (i) Event of supplier default: In the event of
6 supplier default, the utility shall review the
7 contract of the defaulting supplier to determine if
8 the amount of supply is 200 megawatts or greater, and
9 if there are more than 60 days remaining of the
10 contract term. If both of these conditions are met,
11 and the default results in termination of the
12 contract, the utility shall immediately notify the
13 Illinois Power Agency that a request for proposals
14 must be issued to procure replacement power, and the
15 procurement administrator shall run an additional
16 procurement event. If the contracted supply of the
17 defaulting supplier is less than 200 megawatts or
18 there are less than 60 days remaining of the contract
19 term, the utility shall procure power and energy from
20 the applicable regional transmission organization
21 market, including ancillary services, capacity, and
22 day-ahead or real time energy, or both, for the
23 duration of the contract term to replace the
24 contracted supply; provided, however, that if a needed
25 product is not available through the regional
26 transmission organization market it shall be purchased

1 from the wholesale market.

2 (ii) Failure of the procurement process to fully
3 meet the expected load requirement: If the procurement
4 process fails to fully meet the expected load
5 requirement due to insufficient supplier participation
6 or due to a Commission rejection of the procurement
7 results, the procurement administrator, the
8 procurement monitor, and the Commission staff shall
9 meet within 10 days to analyze potential causes of low
10 supplier interest or causes for the Commission
11 decision. If changes are identified that would likely
12 result in increased supplier participation, or that
13 would address concerns causing the Commission to
14 reject the results of the prior procurement event, the
15 procurement administrator may implement those changes
16 and rerun the request for proposals process according
17 to a schedule determined by those parties and
18 consistent with Section 1-75 of the Illinois Power
19 Agency Act and this subsection. In any event, a new
20 request for proposals process shall be implemented by
21 the procurement administrator within 90 days after the
22 determination that the procurement process has failed
23 to fully meet the expected load requirement.

24 (iii) In all cases where there is insufficient
25 supply provided under contracts awarded through the
26 procurement process to fully meet the electric

1 utility's load requirement, the utility shall meet the
2 load requirement by procuring power and energy from
3 the applicable regional transmission organization
4 market, including ancillary services, capacity, and
5 day-ahead or real time energy, or both; provided,
6 however, that if a needed product is not available
7 through the regional transmission organization market
8 it shall be purchased from the wholesale market.

9 (6) The procurement process described in this
10 subsection is exempt from the requirements of the Illinois
11 Procurement Code, pursuant to Section 20-10 of that Code.

12 (f) Within 2 business days after opening the sealed bids,
13 the procurement administrator shall submit a confidential
14 report to the Commission. The report shall contain the results
15 of the bidding for each of the products along with the
16 procurement administrator's recommendation for the acceptance
17 and rejection of bids based on the price benchmark criteria
18 and other factors observed in the process. The procurement
19 monitor also shall submit a confidential report to the
20 Commission within 2 business days after opening the sealed
21 bids. The report shall contain the procurement monitor's
22 assessment of bidder behavior in the process as well as an
23 assessment of the procurement administrator's compliance with
24 the procurement process and rules. The Commission shall review
25 the confidential reports submitted by the procurement
26 administrator and procurement monitor, and shall accept or

1 reject the recommendations of the procurement administrator
2 within 2 business days after receipt of the reports.

3 (g) Within 3 business days after the Commission decision
4 approving the results of a procurement event, the utility
5 shall enter into binding contractual arrangements with the
6 winning suppliers using the standard form contracts; except
7 that the utility shall not be required either directly or
8 indirectly to execute the contracts if a tariff that is
9 consistent with subsection (l) of this Section has not been
10 approved and placed into effect for that utility.

11 (h) The names of the successful bidders and the load
12 weighted average of the winning bid prices for each contract
13 type and for each contract term shall be made available to the
14 public at the time of Commission approval of a procurement
15 event. The Commission, the procurement monitor, the
16 procurement administrator, the Illinois Power Agency, and all
17 participants in the procurement process shall maintain the
18 confidentiality of all other supplier and bidding information
19 in a manner consistent with all applicable laws, rules,
20 regulations, and tariffs. Confidential information, including
21 the confidential reports submitted by the procurement
22 administrator and procurement monitor pursuant to subsection
23 (f) of this Section, shall not be made publicly available and
24 shall not be discoverable by any party in any proceeding,
25 absent a compelling demonstration of need, nor shall those
26 reports be admissible in any proceeding other than one for law

1 enforcement purposes.

2 (i) Within 2 business days after a Commission decision
3 approving the results of a procurement event or such other
4 date as may be required by the Commission from time to time,
5 the utility shall file for informational purposes with the
6 Commission its actual or estimated retail supply charges, as
7 applicable, by customer supply group reflecting the costs
8 associated with the procurement and computed in accordance
9 with the tariffs filed pursuant to subsection (l) of this
10 Section and approved by the Commission.

11 (j) Within 60 days following August 28, 2007 (the
12 effective date of Public Act 95-481), each electric utility
13 that on December 31, 2005 provided electric service to at
14 least 100,000 customers in Illinois shall prepare and file
15 with the Commission an initial procurement plan, which shall
16 conform in all material respects to the requirements of the
17 procurement plan set forth in subsection (b); provided,
18 however, that the Illinois Power Agency Act shall not apply to
19 the initial procurement plan prepared pursuant to this
20 subsection. The initial procurement plan shall identify the
21 portfolio of power and energy products to be procured and
22 delivered for the period June 2008 through May 2009, and shall
23 identify the proposed procurement administrator, who shall
24 have the same experience and expertise as is required of a
25 procurement administrator hired pursuant to Section 1-75 of
26 the Illinois Power Agency Act. Copies of the procurement plan

1 shall be posted and made publicly available on the
2 Commission's website. The initial procurement plan may include
3 contracts for renewable resources that extend beyond May 2009.

4 (i) Within 14 days following filing of the initial
5 procurement plan, any person may file a detailed objection
6 with the Commission contesting the procurement plan
7 submitted by the electric utility. All objections to the
8 electric utility's plan shall be specific, supported by
9 data or other detailed analyses. The electric utility may
10 file a response to any objections to its procurement plan
11 within 7 days after the date objections are due to be
12 filed. Within 7 days after the date the utility's response
13 is due, the Commission shall determine whether a hearing
14 is necessary. If it determines that a hearing is
15 necessary, it shall require the hearing to be completed
16 and issue an order on the procurement plan within 60 days
17 after the filing of the procurement plan by the electric
18 utility.

19 (ii) The order shall approve or modify the procurement
20 plan, approve an independent procurement administrator,
21 and approve or modify the electric utility's tariffs that
22 are proposed with the initial procurement plan. The
23 Commission shall approve the procurement plan if the
24 Commission determines that it will ensure adequate,
25 reliable, affordable, efficient, and environmentally
26 sustainable electric service at the lowest total cost over

1 time, taking into account any benefits of price stability.

2 (k) (Blank).

3 (k-5) (Blank).

4 (l) An electric utility shall recover its costs incurred
5 under this Section, including, but not limited to, the costs
6 of procuring power and energy demand-response resources under
7 this Section. The utility shall file with the initial
8 procurement plan its proposed tariffs through which its costs
9 of procuring power that are incurred pursuant to a
10 Commission-approved procurement plan and those other costs
11 identified in this subsection (l), will be recovered. The
12 tariffs shall include a formula rate or charge designed to
13 pass through both the costs incurred by the utility in
14 procuring a supply of electric power and energy for the
15 applicable customer classes with no mark-up or return on the
16 price paid by the utility for that supply, plus any just and
17 reasonable costs that the utility incurs in arranging and
18 providing for the supply of electric power and energy. The
19 formula rate or charge shall also contain provisions that
20 ensure that its application does not result in over or under
21 recovery due to changes in customer usage and demand patterns,
22 and that provide for the correction, on at least an annual
23 basis, of any accounting errors that may occur. A utility
24 shall recover through the tariff all reasonable costs incurred
25 to implement or comply with any procurement plan that is
26 developed and put into effect pursuant to Section 1-75 of the

1 Illinois Power Agency Act and this Section, including any fees
2 assessed by the Illinois Power Agency, costs associated with
3 load balancing, and contingency plan costs. The electric
4 utility shall also recover its full costs of procuring
5 electric supply for which it contracted before the effective
6 date of this Section in conjunction with the provision of full
7 requirements service under fixed-price bundled service tariffs
8 subsequent to December 31, 2006. All such costs shall be
9 deemed to have been prudently incurred. The pass-through
10 tariffs that are filed and approved pursuant to this Section
11 shall not be subject to review under, or in any way limited by,
12 Section 16-111(i) of this Act. All of the costs incurred by the
13 electric utility associated with the purchase of zero emission
14 credits in accordance with subsection (d-5) of Section 1-75 of
15 the Illinois Power Agency Act and, beginning June 1, 2017, all
16 of the costs incurred by the electric utility associated with
17 the purchase of renewable energy resources in accordance with
18 Sections 1-56 and 1-75 of the Illinois Power Agency Act, shall
19 be recovered through the electric utility's tariffed charges
20 applicable to all of its retail customers, as specified in
21 subsection (k) of Section 16-108 of this Act, and shall not be
22 recovered through the electric utility's tariffed charges for
23 electric power and energy supply to its eligible retail
24 customers.

25 (m) The Commission has the authority to adopt rules to
26 carry out the provisions of this Section. For the public

1 interest, safety, and welfare, the Commission also has
2 authority to adopt rules to carry out the provisions of this
3 Section on an emergency basis immediately following August 28,
4 2007 (the effective date of Public Act 95-481).

5 (n) Notwithstanding any other provision of this Act, any
6 affiliated electric utilities that submit a single procurement
7 plan covering their combined needs may procure for those
8 combined needs in conjunction with that plan, and may enter
9 jointly into power supply contracts, purchases, and other
10 procurement arrangements, and allocate capacity and energy and
11 cost responsibility therefor among themselves in proportion to
12 their requirements.

13 (o) On or before June 1 of each year, the Commission shall
14 hold an informal hearing for the purpose of receiving comments
15 on the prior year's procurement process and any
16 recommendations for change.

17 (p) An electric utility subject to this Section may
18 propose to invest, lease, own, or operate an electric
19 generation facility as part of its procurement plan, provided
20 the utility demonstrates that such facility is the least-cost
21 option to provide electric service to those retail customers
22 included in the plan's electric supply service requirements.
23 If the facility is shown to be the least-cost option and is
24 included in a procurement plan prepared in accordance with
25 Section 1-75 of the Illinois Power Agency Act and this
26 Section, then the electric utility shall make a filing

1 pursuant to Section 8-406 of this Act, and may request of the
2 Commission any statutory relief required thereunder. If the
3 Commission grants all of the necessary approvals for the
4 proposed facility, such supply shall thereafter be considered
5 as a pre-existing contract under subsection (b) of this
6 Section. The Commission shall in any order approving a
7 proposal under this subsection specify how the utility will
8 recover the prudently incurred costs of investing in, leasing,
9 owning, or operating such generation facility through just and
10 reasonable rates charged to those retail customers included in
11 the plan's electric supply service requirements. Cost recovery
12 for facilities included in the utility's procurement plan
13 pursuant to this subsection shall not be subject to review
14 under or in any way limited by the provisions of Section
15 16-111(i) of this Act. Nothing in this Section is intended to
16 prohibit a utility from filing for a fuel adjustment clause as
17 is otherwise permitted under Section 9-220 of this Act.

18 (q) If the Illinois Power Agency filed with the
19 Commission, under Section 16-111.5 of this Act, its proposed
20 procurement plan for the period commencing June 1, 2017, and
21 the Commission has not yet entered its final order approving
22 the plan on or before the effective date of this amendatory Act
23 of the 99th General Assembly, then the Illinois Power Agency
24 shall file a notice of withdrawal with the Commission, after
25 the effective date of this amendatory Act of the 99th General
26 Assembly, to withdraw the proposed procurement of renewable

1 energy resources to be approved under the plan, other than the
2 procurement of renewable energy credits from distributed
3 renewable energy generation devices using funds previously
4 collected from electric utilities' retail customers that take
5 service pursuant to electric utilities' hourly pricing tariff
6 or tariffs and, for an electric utility that serves less than
7 100,000 retail customers in the State, other than the
8 procurement of renewable energy credits from distributed
9 renewable energy generation devices. Upon receipt of the
10 notice, the Commission shall enter an order that approves the
11 withdrawal of the proposed procurement of renewable energy
12 resources from the plan. The initially proposed procurement of
13 renewable energy resources shall not be approved or be the
14 subject of any further hearing, investigation, proceeding, or
15 order of any kind.

16 This amendatory Act of the 99th General Assembly preempts
17 and supersedes any order entered by the Commission that
18 approved the Illinois Power Agency's procurement plan for the
19 period commencing June 1, 2017, to the extent it is
20 inconsistent with the provisions of this amendatory Act of the
21 99th General Assembly. To the extent any previously entered
22 order approved the procurement of renewable energy resources,
23 the portion of that order approving the procurement shall be
24 void, other than the procurement of renewable energy credits
25 from distributed renewable energy generation devices using
26 funds previously collected from electric utilities' retail

1 customers that take service under electric utilities' hourly
2 pricing tariff or tariffs and, for an electric utility that
3 serves less than 100,000 retail customers in the State, other
4 than the procurement of renewable energy credits for
5 distributed renewable energy generation devices.

6 (Source: P.A. 99-906, eff. 6-1-17.)

7 (220 ILCS 5/16-128A)

8 Sec. 16-128A. Certification of installers, maintainers, or
9 repairers.

10 (a) Within 18 months of the effective date of this
11 amendatory Act of the 97th General Assembly, the Commission
12 shall adopt rules, including emergency rules, establishing
13 certification requirements ensuring that entities installing
14 distributed generation facilities are in compliance with the
15 requirements of subsection (a) of Section 16-128 of this Act.

16 For purposes of this Section, the phrase "entities
17 installing distributed generation facilities" shall include,
18 but not be limited to, all entities that are exempt from the
19 definition of "alternative retail electric supplier" under
20 item (v) of Section 16-102 of this Act. For purposes of this
21 Section, the phrase "self-installer" means an individual who
22 (i) leases or purchases a cogeneration facility for his or her
23 own personal use and (ii) installs such cogeneration or
24 self-generation facility on his or her own premises without
25 the assistance of any other person.

1 (b) In addition to any authority granted to the Commission
2 under this Act, the Commission is also authorized to: (1)
3 determine which entities are subject to certification under
4 this Section; (2) impose reasonable certification fees and
5 penalties; (3) adopt disciplinary procedures; (4) investigate
6 any and all activities subject to this Section, including
7 violations thereof; (5) adopt procedures to issue or renew, or
8 to refuse to issue or renew, a certification or to revoke,
9 suspend, place on probation, reprimand, or otherwise
10 discipline a certified entity under this Act or take other
11 enforcement action against an entity subject to this Section;
12 and (6) prescribe forms to be issued for the administration
13 and enforcement of this Section.

14 (c) No electric utility shall provide a retail customer
15 with net metering service related to interconnection of that
16 customer's distributed generation facility unless the customer
17 provides the electric utility with (i) a certification that
18 the customer installing the distributed generation facility
19 was a self-installer or (ii) evidence that the distributed
20 generation facility was installed by an entity certified under
21 this Section that is also in good standing with the
22 Commission. For purposes of this subsection, a retail customer
23 includes that customer's employees, officers, and agents. An
24 electric utility shall file a tariff or tariffs with the
25 Commission setting forth the documentation, as specified by
26 Commission rule, that a retail customer must provide to an

1 electric utility. The provisions of this subsection (c) shall
2 apply on or after the effective date of the Commission's rules
3 prescribed pursuant to subsection (a) of this Section.

4 (d) Within 180 days after the effective date of this
5 amendatory Act of the 97th General Assembly, the Commission
6 shall initiate a rulemaking proceeding to establish
7 certification requirements that shall be applicable to persons
8 or entities that install, maintain, or repair electric vehicle
9 charging stations. The notification and certification
10 requirements of this Section shall only be applicable to
11 individuals or entities that perform work on or within an
12 electric vehicle charging station, including, but not limited
13 to, connection of power to an electric vehicle charging
14 station.

15 ~~For the purposes of this Section "electric vehicle~~
16 ~~charging station" means any facility or equipment that is used~~
17 ~~to charge a battery or other energy storage device of an~~
18 ~~electric vehicle.~~

19 Rules regulating the installation, maintenance, or repair
20 of electric vehicle charging stations, in which the Commission
21 may establish separate requirements based upon the
22 characteristics of electric vehicle charging stations, so long
23 as it is in accordance with the requirements of subsection (a)
24 of Section 16-128 and Section 16-128A of this Act, shall:

- 25 (1) establish a certification process for persons or
26 entities that install, maintain, or repair of electric

1 vehicle charging stations;

2 (2) require persons or entities that install,
3 maintain, or repair electric vehicle stations to be
4 certified to do business and to be bonded in the State;

5 (3) ensure that persons or entities that install,
6 maintain, or repair electric vehicle charging stations
7 have the requisite knowledge, skills, training,
8 experience, and competence to perform functions in a safe
9 and reliable manner as required under subsection (a) of
10 Section 16-128 of this Act;

11 (4) impose reasonable certification fees and penalties
12 on persons or entities that install, maintain, or repair
13 of electric vehicle charging stations for noncompliance of
14 the rules adopted under this subsection;

15 (5) ensure that all persons or entities that install,
16 maintain, or repair electric vehicle charging stations
17 conform to applicable building and electrical codes;

18 (6) ensure that all electric vehicle charging stations
19 meet recognized industry standards as the Commission deems
20 appropriate, such as the National Electric Code (NEC) and
21 standards developed or created by the Institute of
22 Electrical and Electronics Engineers (IEEE), the Electric
23 Power Research Institute (EPRI), the Detroit Edison
24 Institute (DTE), the Underwriters Laboratory (UL), the
25 Society of Automotive Engineers (SAE), and the National
26 Institute of Standards and Technology (NIST);

1 (7) include any additional requirements that the
2 Commission deems reasonable to ensure that persons or
3 entities that install, maintain, or repair electric
4 vehicle charging stations meet adequate training,
5 financial, and competency requirements;

6 (8) ensure that the obligations required under this
7 Section and subsection (a) of Section 16-128 of this Act
8 are met prior to the interconnection of any electric
9 vehicle charging station;

10 (9) ensure electric vehicle charging stations
11 installed by a self-installer are not used for any
12 commercial purpose;

13 (10) establish an inspection procedure for the
14 conversion of electric vehicle charging stations installed
15 by a self-installer if it is determined that the
16 self-installed electric vehicle charging station is being
17 used for commercial purposes;

18 (11) establish the requirement that all persons or
19 entities that install electric vehicle charging stations
20 shall notify the servicing electric utility in writing of
21 plans to install an electric vehicle charging station and
22 shall notify the servicing electric utility in writing
23 when installation is complete;

24 (12) ensure that all persons or entities that install,
25 maintain, or repair electric vehicle charging stations
26 obtain certificates of insurance in sufficient amounts and

1 coverages that the Commission so determines and, if
2 necessary as determined by the Commission, names the
3 affected public utility as an additional insured; and

4 (13) identify and determine the training or other
5 programs by which persons or entities may obtain the
6 requisite training, skills, or experience necessary to
7 achieve and maintain compliance with the requirements set
8 forth in this subsection and subsection (a) of Section
9 16-128 to install, maintain, or repair electric vehicle
10 charging stations.

11 Within 18 months after the effective date of this
12 amendatory Act of the 97th General Assembly, the Commission
13 shall adopt rules, and may, if it deems necessary, adopt
14 emergency rules, for the installation, maintenance, or repair
15 of electric vehicle charging stations.

16 All retail customers who own, maintain, or repair an
17 electric vehicle charging station shall provide the servicing
18 electric utility (i) a certification that the customer
19 installing the electric vehicle charging station was a
20 self-installer or (ii) evidence that the electric vehicle
21 charging station was installed by an entity certified under
22 this subsection (d) that is also in good standing with the
23 Commission. For purposes of this subsection (d), a retail
24 customer includes that retail customer's employees, officers,
25 and agents. If the electric vehicle charging station was not
26 installed by a self-installer, then the person or entity that

1 plans to install the electric vehicle charging station shall
2 provide notice to the servicing electric utility prior to
3 installation and when installation is complete and provide any
4 other information required by the Commission's rules
5 established under subsection (d) of this Section. An electric
6 utility shall file a tariff or tariffs with the Commission
7 setting forth the documentation, as specified by Commission
8 rule, that a retail customer who owns, uses, operates, or
9 maintains an electric vehicle charging station must provide to
10 an electric utility.

11 For the purposes of this subsection, an electric vehicle
12 charging station shall constitute a distribution facility or
13 equipment as that term is used in subsection (a) of Section
14 16-128 of this Act. The phrase "self-installer" means an
15 individual who (i) leases or purchases an electric vehicle
16 charging station for his or her own personal use and (ii)
17 installs an electric vehicle charging station on his or her
18 own premises without the assistance of any other person.

19 (e) Fees and penalties collected under this Section shall
20 be deposited into the Public Utility Fund and used to fund the
21 Commission's compliance with the obligations imposed by this
22 Section.

23 (f) The rules established under subsection (d) of this
24 Section shall specify the initial dates for compliance with
25 the rules.

26 (g) Within 18 months of the effective date of this

1 amendatory Act of the 99th General Assembly, the Commission
2 shall adopt rules, including emergency rules, establishing a
3 process for entities installing a new utility-scale solar
4 project to certify compliance with the requirements of this
5 Section. For purposes of this Section, the phrase "entities
6 installing a new utility-scale solar project" shall include,
7 but is not limited to, any entity installing new photovoltaic
8 projects as such terms are defined in subsection (c) of
9 Section 1-75 of the Illinois Power Agency Act.

10 The process shall include an option to complete the
11 certification electronically by completing forms on-line. An
12 entity installing a new utility-scale solar project shall be
13 permitted to complete certification after the subject work has
14 been completed. The Commission shall maintain on its website a
15 list of entities installing new utility-scale solar projects
16 measures that have successfully completed the certification
17 process.

18 (h) In addition to any authority granted to the Commission
19 under this Act, the Commission is also authorized to: (1)
20 determine which entities are subject to certification under
21 subsection (g) of this Section; (2) impose reasonable
22 certification fees and penalties; (3) adopt disciplinary
23 procedures; (4) investigate any and all activities subject to
24 subsection (g) or this subsection (h) of this Section,
25 including violations thereof; (5) adopt procedures to issue or
26 renew, or to refuse to issue or renew, a certification or to

1 revoke, suspend, place on probation, reprimand, or otherwise
2 discipline a certified entity under subsection (g) of this
3 Section or take other enforcement action against an entity
4 subject to subsection (g) or this subsection (h) of this
5 Section; (6) prescribe forms to be issued for the
6 administration and enforcement of subsection (g) and this
7 subsection (h) of this Section; and (7) establish requirements
8 to ensure that entities installing a new photovoltaic project
9 have the requisite knowledge, skills, training, experience,
10 and competence to perform in a safe and reliable manner as
11 required by subsection (a) of Section 16-128 of this Act.

12 (i) The certification of persons or entities that install,
13 maintain, or repair new photovoltaic projects, distributed
14 generation facilities, and electric vehicle charging stations
15 as set forth in this Section is an exclusive power and function
16 of the State. A home rule unit or other units of local
17 government authority may subject persons or entities that
18 install, maintain, or repair new photovoltaic projects,
19 distributed generation facilities, or electric vehicle
20 charging stations as set forth in this Section to any
21 applicable local licensing, siting, and permitting
22 requirements otherwise permitted under law so long as only
23 Commission-certified persons or entities are authorized to
24 install, maintain, or repair new photovoltaic projects,
25 distributed generation facilities, or electric vehicle
26 charging stations. This Section is a limitation under

1 subsection (h) of Section 6 of Article VII of the Illinois
2 Constitution on the exercise by home rule units of powers and
3 functions exclusively exercised by the State.

4 (Source: P.A. 99-906, eff. 6-1-17; 100-16, eff. 6-30-17.)

5 Section 15. The Prevailing Wage Act is amended by changing
6 Section 2 as follows:

7 (820 ILCS 130/2) (from Ch. 48, par. 39s-2)

8 Sec. 2. This Act applies to the wages of laborers,
9 mechanics and other workers employed in any public works, as
10 hereinafter defined, by any public body and to anyone under
11 contracts for public works. This includes any maintenance,
12 repair, assembly, or disassembly work performed on equipment
13 whether owned, leased, or rented.

14 As used in this Act, unless the context indicates
15 otherwise:

16 "Public works" means all fixed works constructed or
17 demolished by any public body, or paid for wholly or in part
18 out of public funds. "Public works" as defined herein includes
19 all projects financed in whole or in part with bonds, grants,
20 loans, or other funds made available by or through the State or
21 any of its political subdivisions, including but not limited
22 to: bonds issued under the Industrial Project Revenue Bond Act
23 (Article 11, Division 74 of the Illinois Municipal Code), the
24 Industrial Building Revenue Bond Act, the Illinois Finance

1 Authority Act, the Illinois Sports Facilities Authority Act,
2 or the Build Illinois Bond Act; loans or other funds made
3 available pursuant to the Build Illinois Act; loans or other
4 funds made available pursuant to the Riverfront Development
5 Fund under Section 10-15 of the River Edge Redevelopment Zone
6 Act; or funds from the Fund for Illinois' Future under Section
7 6z-47 of the State Finance Act, funds for school construction
8 under Section 5 of the General Obligation Bond Act, funds
9 authorized under Section 3 of the School Construction Bond
10 Act, funds for school infrastructure under Section 6z-45 of
11 the State Finance Act, and funds for transportation purposes
12 under Section 4 of the General Obligation Bond Act. "Public
13 works" also includes (i) all projects financed in whole or in
14 part with funds from the Department of Commerce and Economic
15 Opportunity under the Illinois Renewable Fuels Development
16 Program Act for which there is no project labor agreement;
17 (ii) all work performed pursuant to a public private agreement
18 under the Public Private Agreements for the Illiana Expressway
19 Act or the Public-Private Agreements for the South Suburban
20 Airport Act; and (iii) all projects undertaken under a
21 public-private agreement under the Public-Private Partnerships
22 for Transportation Act. "Public works" also includes all
23 projects at leased facility property used for airport purposes
24 under Section 35 of the Local Government Facility Lease Act.
25 "Public works" also includes the construction of a new wind
26 power facility by a business designated as a High Impact

1 Business under Section 5.5(a)(3)(E) of the Illinois Enterprise
2 Zone Act. "Public works" also includes any facility financed
3 in whole or in part with renewable energy resources procured
4 pursuant to Section 1-75 of the Illinois Power Agency Act and
5 any photovoltaic electric production facility constructed
6 pursuant to Section 8-218 of the Public Utilities Act. "Public
7 works" does not include work done directly by any public
8 utility company, whether or not done under public supervision
9 or direction, or paid for wholly or in part out of public
10 funds. "Public works" also includes any corrective action
11 performed pursuant to Title XVI of the Environmental
12 Protection Act for which payment from the Underground Storage
13 Tank Fund is requested. "Public works" does not include
14 projects undertaken by the owner at an owner-occupied
15 single-family residence or at an owner-occupied unit of a
16 multi-family residence. "Public works" does not include work
17 performed for soil and water conservation purposes on
18 agricultural lands, whether or not done under public
19 supervision or paid for wholly or in part out of public funds,
20 done directly by an owner or person who has legal control of
21 those lands.

22 "Construction" means all work on public works involving
23 laborers, workers or mechanics. This includes any maintenance,
24 repair, assembly, or disassembly work performed on equipment
25 whether owned, leased, or rented.

26 "Locality" means the county where the physical work upon

1 public works is performed, except (1) that if there is not
2 available in the county a sufficient number of competent
3 skilled laborers, workers and mechanics to construct the
4 public works efficiently and properly, "locality" includes any
5 other county nearest the one in which the work or construction
6 is to be performed and from which such persons may be obtained
7 in sufficient numbers to perform the work and (2) that, with
8 respect to contracts for highway work with the Department of
9 Transportation of this State, "locality" may at the discretion
10 of the Secretary of the Department of Transportation be
11 construed to include two or more adjacent counties from which
12 workers may be accessible for work on such construction.

13 "Public body" means the State or any officer, board or
14 commission of the State or any political subdivision or
15 department thereof, or any institution supported in whole or
16 in part by public funds, and includes every county, city,
17 town, village, township, school district, irrigation, utility,
18 reclamation improvement or other district and every other
19 political subdivision, district or municipality of the state
20 whether such political subdivision, municipality or district
21 operates under a special charter or not.

22 "Labor organization" means an organization that is the
23 exclusive representative of an employer's employees recognized
24 or certified pursuant to the National Labor Relations Act.

25 The terms "general prevailing rate of hourly wages",
26 "general prevailing rate of wages" or "prevailing rate of

1 wages" when used in this Act mean the hourly cash wages plus
2 annualized fringe benefits for training and apprenticeship
3 programs approved by the U.S. Department of Labor, Bureau of
4 Apprenticeship and Training, health and welfare, insurance,
5 vacations and pensions paid generally, in the locality in
6 which the work is being performed, to employees engaged in
7 work of a similar character on public works.

8 (Source: P.A. 100-1177, eff. 6-1-19.)

9 Section 97. Severability. The provisions of this Act are
10 severable under Section 1.31 of the Statute on Statutes.

11 Section 99. Effective date. This Act takes effect upon
12 becoming law.

1 INDEX

2 Statutes amended in order of appearance

3 20 ILCS 3855/1-10

4 20 ILCS 3855/1-75

5 220 ILCS 5/5-117

6 220 ILCS 5/8-103B

7 220 ILCS 5/8-218 new

8 220 ILCS 5/9-244.5 new

9 220 ILCS 5/16-102

10 220 ILCS 5/16-107.6

11 220 ILCS 5/16-108.5

12 220 ILCS 5/16-108.19 new

13 220 ILCS 5/16-108.20 new

14 220 ILCS 5/16-111.5

15 220 ILCS 5/16-128A

16 820 ILCS 130/2 from Ch. 48, par. 39s-2