

104TH GENERAL ASSEMBLY

State of Illinois

2025 and 2026

HB4995

by Rep. Robyn Gabel

SYNOPSIS AS INTRODUCED:

See Index

Creates the Electric Transmission Facilities Siting Act. Defines terms. Requires that, in the siting of new electric transmission facilities, available corridors be used in the following order of priority: (1) existing public utility corridors; (2) highway corridors; and (3) new corridors. Provides that a public utility or developer may construct, place, or maintain a high-voltage electric service line on a public right-of-way or along a highway if (i) the public utility or developer submits a colocation request for the high-voltage electric service line to the Secretary of Transportation and (ii) the Secretary reviews and approves the colocation request. Requires a public utility or developer to develop a constructability report in consultation with the Department of Transportation and requires the public utility or developer and the Department to follow the terms and conditions of the constructability report during the planning and approval process for the siting of a high-voltage electric service line. Sets forth requirements for the content of the constructability report. Amends the Public Utilities Act. In provisions concerning distributed generation rebates, provides that the owner or operator of distributed generation that, before January 1, 2025 (rather than before the threshold date), is eligible for net metering under the Act may apply for a base rebate for an associated energy storage device behind the same retail customer meter as the distributed generation, regardless of whether the distributed generation applies for a rebate for the distributed generation device. Provides that, after the threshold date, a stand-alone energy storage system that is neither paired with distributed generation nor with any electric load beyond the electric load that is used by the energy storage system itself (rather than a stand-alone energy storage system) shall be compensated with a rebate of \$250 per kilowatt-hour of nameplate capacity. Amends the Environmental Protection Act. In provisions concerning greenhouse gases, provides that the Environmental Protection Agency and the Illinois Power Agency shall file a plan to reduce or delay certain emissions reductions requirements with the Illinois Commerce Commission for review in conjunction with the integrated resource plan under certain provisions of the Public Utilities Act. Makes other changes. Effective immediately.

LRB104 19660 AAS 33109 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. Short title. This Act may be cited as the
5 Electric Transmission Facilities Siting Act.

6 Section 5. Definitions.

7 "Commission" means the Illinois Commerce Commission.

8 "Department" means the Illinois Department of
9 Transportation.

10 "Developer" means an individual, partnership, corporation,
11 or other entity seeking to build or maintain a high-voltage
12 electric service line.

13 "Electric transmission facilities" means electric
14 transmission lines, transmission towers, conductors,
15 insulators, foundations, grounding systems, access roads, and
16 any associated electric facilities, including transmission
17 substations.

18 "Highway" has the meaning given to that term in Section
19 2-202 of the Illinois Highway Code.

20 "High-voltage electric service line" means an electric
21 transmission line having a design voltage of 100,000 volts or
22 more.

23 "Secretary" means the Secretary of Transportation.

1 "Public utility" has the meaning given to that term in
2 Section 3-105 of the Public Utilities Act.

3 Section 10. Siting of electric transmission facilities.

4 (a) In the siting of new electric transmission facilities,
5 including high-voltage electric service lines, available
6 corridors shall be used in the following order of priority:

7 (1) Existing public utility corridors.

8 (2) Highway corridors.

9 (3) New corridors.

10 (b) Permitting on the corridors listed in subsection (a)
11 shall be done, to the greatest extent possible, in a manner
12 that accounts for economic and engineering considerations, the
13 reliability of the electric system, and the protection of the
14 environment.

15 Section 15. High-voltage electric service line colocation
16 requests.

17 (a) A public utility or developer may construct, place, or
18 maintain a high-voltage electric service line on a public
19 right-of-way or along a highway if (i) the public utility or
20 developer submits to the Secretary a colocation request for
21 the high-voltage electric service line and (ii) the Secretary
22 reviews and approves the colocation request.

23 (b) The Secretary may deny a colocation request under this
24 Section if the Secretary determines that the construction,

1 placement, or maintenance of a high-voltage electric service
2 line on a public right-of-way or along a highway would
3 endanger public safety or would interfere with the proper
4 function of the highway.

5 (c) If the Secretary denies a colocation request under
6 this Section, the Secretary shall submit the reasons for the
7 denial to the applicable public utility or developer and the
8 Commission within 90 days after the issuance of the denial.

9 Section 20. High-voltage electric service line evaluation;
10 constructability report.

11 (a) A public utility or developer may submit a written
12 request to the Department for an evaluation of the corridors
13 described in subsection (a) of Section 10 for possible
14 locations for a high-voltage electric service line. Within 30
15 days after receipt of a written request under this subsection
16 (a), the Secretary shall assign a project coordinator to the
17 request. A project coordinator, upon assignment to a request,
18 shall begin the evaluation in coordination with the applicable
19 public utility or developer.

20 (b) The Department shall inform a public utility or
21 developer about any of the Department's current plans or
22 projects that could impact the public utility's or developer's
23 potential construction or placement of a high-voltage electric
24 service line within a corridor.

25 (c) After an evaluation under subsection (a) identifies an

1 acceptable location within a corridor, a public utility or
2 developer, in consultation with the Department, shall develop
3 a constructability report. The constructability report shall
4 include (i) the terms and conditions for the siting of the
5 high-voltage electric service line and (ii) an agreed-upon
6 time frame during which the Department may not request the
7 relocation of the high-voltage electric service line. The
8 Department shall issue a permit to the public utility or
9 developer for the use of a public right-of-way within the
10 corridor for the siting of a high-voltage electric service
11 line only after a constructability report is approved by both
12 the Department and the public utility or developer.

13 (d) A public utility or developer and the Department shall
14 follow the terms and conditions of the approved
15 constructability report during the planning and approval
16 process for the siting of a high-voltage electric service
17 line. If the Department requires the relocation of a
18 high-voltage electric service line on a public right-of-way by
19 a specific date, the Department shall give the applicable
20 public utility or developer notice of the required relocation
21 no less than 10 years before the date of the required
22 relocation.

23 (e) If the Department requires the relocation of a
24 high-voltage electric service line during the prohibited time
25 frame specified in the constructability report or the
26 Department provides notice of the required relocation of a

1 high-voltage electric service line to a public utility or
2 developer less than 10 years before the date of the required
3 relocation, the Department shall be responsible for 75% of the
4 costs incurred by the public utility or developer in the
5 relocation of the high-voltage electric service line.

6 Section 25. The Public Utilities Act is amended by
7 changing Sections 16-107.6 and 16-107.9 as follows:

8 (220 ILCS 5/16-107.6)

9 (Text of Section before amendment by P.A. 104-458)

10 Sec. 16-107.6. Distributed generation rebate.

11 (a) In this Section:

12 "Additive services" means the services that distributed
13 energy resources provide to the energy system and society that
14 are not (1) already included in the base rebates for
15 system-wide grid services; or (2) otherwise already
16 compensated. Additive services may reflect, but shall not be
17 limited to, any geographic, time-based, performance-based, and
18 other benefits of distributed energy resources, as well as the
19 present and future technological capabilities of distributed
20 energy resources and present and future grid needs.

21 "Distributed energy resource" means a wide range of
22 technologies that are located on the customer side of the
23 customer's electric meter, including, but not limited to,
24 distributed generation, energy storage, electric vehicles, and

1 demand response technologies.

2 "Energy storage system" means commercially available
3 technology that is capable of absorbing energy and storing it
4 for a period of time for use at a later time, including, but
5 not limited to, electrochemical, thermal, and
6 electromechanical technologies, and may be interconnected
7 behind the customer's meter or interconnected behind its own
8 meter.

9 "Smart inverter" means a device that converts direct
10 current into alternating current and meets the IEEE 1547-2018
11 equipment standards. Until devices that meet the IEEE
12 1547-2018 standard are available, devices that meet the UL
13 1741 SA standard are acceptable.

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

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

18 "System-wide grid services" means the benefits that a
19 distributed energy resource provides to the distribution grid
20 for a period of no less than 25 years. System-wide grid
21 services do not vary by location, time, or the performance
22 characteristics of the distributed energy resource.
23 System-wide grid services include, but are not limited to,
24 avoided or deferred distribution capacity costs, resilience
25 and reliability benefits, avoided or deferred distribution
26 operation and maintenance costs, distribution voltage and

1 power quality benefits, and line loss reductions.

2 "Threshold date" means December 31, 2024 or the date on
3 which the utility's tariff or tariffs setting the new
4 compensation values established under subsection (e) take
5 effect, whichever is later.

6 (b) An electric utility that serves more than 200,000
7 customers in the State shall file a petition with the
8 Commission requesting approval of the utility's tariff to
9 provide a rebate to the owner or operator of distributed
10 generation, including third-party owned systems, that meets
11 the following criteria:

12 (1) has a nameplate generating capacity no greater
13 than 5,000 kilowatts and is primarily used to offset a
14 customer's electricity load;

15 (2) is located on the customer's side of the billing
16 meter and for the customer's own use;

17 (3) is interconnected to electric distribution
18 facilities owned by the electric utility under rules
19 adopted by the Commission by means of one or more
20 inverters or smart inverters required by this Section, as
21 applicable.

22 For purposes of this Section, "distributed generation"
23 shall satisfy the definition of distributed renewable energy
24 generation device set forth in Section 1-10 of the Illinois
25 Power Agency Act to the extent such definition is consistent
26 with the requirements of this Section.

1 In addition, any new photovoltaic distributed generation
2 that is installed after June 1, 2017 (the effective date of
3 Public Act 99-906) must be installed by a qualified person, as
4 defined by subsection (i) of Section 1-56 of the Illinois
5 Power Agency Act.

6 The tariff shall include a base rebate that compensates
7 distributed generation for the system-wide grid services
8 associated with distributed generation and, after the
9 proceeding described in subsection (e) of this Section, an
10 additional payment or payments for the additive services. The
11 tariff shall provide that the smart inverter or smart
12 inverters associated with the distributed generation shall
13 provide autonomous response to grid conditions through its
14 default settings as approved by the Commission. Default
15 settings may not be changed after the execution of the
16 interconnection agreement except by mutual agreement between
17 the utility and the owner or operator of the distributed
18 generation. Nothing in this Section shall negate or supersede
19 Institute of Electrical and Electronics Engineers equipment
20 standards or other similar standards or requirements. The
21 tariff shall not limit the ability of the smart inverter or
22 smart inverters or other distributed energy resource to
23 provide wholesale market products such as regulation, demand
24 response, or other services, or limit the ability of the owner
25 of the smart inverter or the other distributed energy resource
26 to receive compensation for providing those wholesale market

1 products or services.

2 (b-5) Within 30 days after the effective date of this
3 amendatory Act of the 102nd General Assembly, each electric
4 public utility with 3,000,000 or more retail customers shall
5 file a tariff with the Commission that further compensates any
6 retail customer that installs or has installed photovoltaic
7 facilities paired with energy storage facilities on or
8 adjacent to its premises for the benefits the facilities
9 provide to the distribution grid. The tariff shall provide
10 that, in addition to the other rebates identified in this
11 Section, the electric utility shall rebate to such retail
12 customer (i) the previously incurred and future costs of
13 installing interconnection facilities and related
14 infrastructure to enable full participation in the PJM
15 Interconnection, LLC or its successor organization frequency
16 regulation market; and (ii) all wholesale demand charges
17 incurred after the effective date of this amendatory Act of
18 the 102nd General Assembly. The Commission shall approve, or
19 approve with modification, the tariff within 120 days after
20 the utility's filing.

21 (c) The proposed tariff authorized by subsection (b) of
22 this Section shall include the following participation terms
23 for rebates to be applied under this Section for distributed
24 generation that satisfies the criteria set forth in subsection
25 (b) of this Section:

26 (1) The owner or operator of distributed generation

1 that services customers not eligible for net metering
2 under subsection (d), (d-5), or (e) of Section 16-107.5 of
3 this Act may apply for a rebate as provided for in this
4 Section. Until the threshold date, the value of the rebate
5 shall be \$250 per kilowatt of nameplate generating
6 capacity, measured as nominal DC power output, of that
7 customer's distributed generation. To the extent the
8 distributed generation also has an associated energy
9 storage, then the energy storage system shall be
10 separately compensated with a base rebate of \$250 per
11 kilowatt-hour of nameplate capacity. Any distributed
12 generation device that is compensated for storage in this
13 subsection (1) before the threshold date shall participate
14 in one or more programs determined through the Multi-Year
15 Integrated Grid Planning process that are designed to meet
16 peak reduction and flexibility. After the threshold date,
17 the value of the base rebate and additional compensation
18 for any additive services shall be as determined by the
19 Commission in the proceeding described in subsection (e)
20 of this Section, provided that the value of the base
21 rebate for system-wide grid services shall not be lower
22 than \$250 per kilowatt of nameplate generating capacity of
23 distributed generation or community renewable generation
24 project.

25 (2) The owner or operator of distributed generation
26 that, before the threshold date, would have been eligible

1 for net metering under subsection (d), (d-5), or (e) of
2 Section 16-107.5 of this Act and that has not previously
3 received a distributed generation rebate, may apply for a
4 rebate as provided for in this Section. Until the
5 threshold date, the value of the base rebate shall be \$300
6 per kilowatt of nameplate generating capacity, measured as
7 nominal DC power output, of the distributed generation.
8 The owner or operator of distributed generation that,
9 before the threshold date, is eligible for net metering
10 under subsection (d), (d-5), or (e) of Section 16-107.5 of
11 this Act may apply for a base rebate for an associated
12 energy storage device behind the same retail customer
13 meter as the distributed generation, regardless of whether
14 the distributed generation applies for a rebate for the
15 distributed generation device. The energy storage system
16 shall be separately compensated at a base payment of \$300
17 per kilowatt-hour of nameplate capacity. Any distributed
18 generation device that is compensated for storage in this
19 subsection (2) before the threshold date shall participate
20 in a peak time rebate program, hourly pricing program, or
21 time-of-use rate program offered by the applicable
22 electric utility. After the threshold date, the value of
23 the base rebate and additional compensation for any
24 additive services shall be as determined by the Commission
25 in the proceeding described in subsection (e) of this
26 Section, provided that, prior to December 31, 2029, the

1 value of the base rebate for system-wide services shall
2 not be lower than \$300 per kilowatt of nameplate
3 generating capacity of distributed generation, after which
4 it shall not be lower than \$250 per kilowatt of nameplate
5 capacity. The eligibility of energy storage devices that
6 are interconnected behind the same retail customer meter
7 as the distributed generation shall not be limited to
8 energy storage devices interconnected after the effective
9 date of this amendatory Act of the 103rd General Assembly.
10 To the extent that an electric utility's tariffs are
11 inconsistent with the requirements of this paragraph (2)
12 as modified by this amendatory Act of the 103rd General
13 Assembly, such electric utility shall, within 30 days,
14 file modified tariffs consistent with the requirements of
15 this paragraph (2).

16 (3) Upon approval of a rebate application submitted
17 under this subsection (c), the retail customer shall no
18 longer be entitled to receive any delivery service credits
19 for the excess electricity generated by its facility and
20 shall be subject to the provisions of subsection (n) of
21 Section 16-107.5 of this Act unless the owner or operator
22 receives a rebate only for an energy storage device and
23 not for the distributed generation device.

24 (4) To be eligible for a rebate described in this
25 subsection (c), the owner or operator of the distributed
26 generation must have a smart inverter installed and in

1 operation on the distributed generation.

2 (d) The Commission shall review the proposed tariff
3 authorized by subsection (b) of this Section and may make
4 changes to the tariff that are consistent with this Section
5 and with the Commission's authority under Article IX of this
6 Act, subject to notice and hearing. Following notice and
7 hearing, the Commission shall issue an order approving, or
8 approving with modification, such tariff no later than 240
9 days after the utility files its tariff. Upon the effective
10 date of this amendatory Act of the 102nd General Assembly, an
11 electric utility shall file a petition with the Commission to
12 amend and update any existing tariffs to comply with
13 subsections (b) and (c).

14 (e) By no later than June 30, 2023, the Commission shall
15 open an independent, statewide investigation into the value
16 of, and compensation for, distributed energy resources. The
17 Commission shall conduct the investigation, but may arrange
18 for experts or consultants independent of the utilities and
19 selected by the Commission to assist with the investigation.
20 The cost of the investigation shall be shared by the utilities
21 filing tariffs under subsection (b) of this Section but may be
22 recovered as an expense through normal ratemaking procedures.

23 (1) The Commission shall ensure that the investigation
24 includes, at minimum, diverse sets of stakeholders; a
25 review of best practices in calculating the value of
26 distributed energy resource benefits; a review of the full

1 value of the distributed energy resources and the manner
2 in which each component of that value is or is not
3 otherwise compensated; and assessments of how the value of
4 distributed energy resources may evolve based on the
5 present and future technological capabilities of
6 distributed energy resources and based on present and
7 future grid needs.

8 (2) The Commission's final order concluding this
9 investigation shall establish an annual process and
10 formula for the compensation of distributed generation and
11 energy storage systems, and an initial set of inputs for
12 that formula. The Commission's final order concluding this
13 investigation shall establish base rebates that compensate
14 distributed generation, community renewable generation
15 projects and energy storage systems for the system-wide
16 grid services that they provide. Those base rebate values
17 shall be consistent across the state, and shall not vary
18 by customer, customer class, customer location, or any
19 other variable. With respect to rebates for distributed
20 generation or community renewable generation projects,
21 that rebate shall not be lower than \$250 per kilowatt of
22 nameplate generating capacity of the distributed
23 generation or community renewable generation project. The
24 Commission's final order concluding this proceeding shall
25 also direct the utilities to update the formula, on an
26 annual basis, with inputs derived from their integrated

1 grid plans developed pursuant to Section 16-105.17. The
2 base rebate shall be updated annually based on the annual
3 updates to the formula inputs, but, with respect to
4 rebates for distributed generation or community renewable
5 generation projects, shall be no lower than \$250 per
6 kilowatt of nameplate generating capacity of the
7 distributed generation or community renewable generation
8 project.

9 (3) The Commission shall also determine, as a part of
10 its investigation under this subsection, whether
11 distributed energy resources can provide any additive
12 services. Those additive services may include services
13 that are provided through utility-controlled responses to
14 grid conditions. If the Commission determines that
15 distributed energy resources can provide additive grid
16 services, the Commission shall determine the terms and
17 conditions for the operation and compensation of those
18 services. That compensation shall be above and beyond the
19 base rebate that the distributed energy generation,
20 community renewable generation project and energy storage
21 system receives. Compensation for additive services may
22 vary by location, time, performance characteristics,
23 technology types, or other variables.

24 (4) The Commission shall ensure that compensation for
25 distributed energy resources, including base rebates and
26 any payments for additive services, shall reflect all

1 reasonably known and measurable values of the distributed
2 generation over its full expected useful life.
3 Compensation for additive services shall reflect, but
4 shall not be limited to, any geographic, time-based,
5 performance-based, and other benefits of distributed
6 generation, as well as the present and future
7 technological capabilities of distributed energy resources
8 and present and future grid needs.

9 (5) The Commission shall consider the electric
10 utility's integrated grid plan developed pursuant to
11 Section 16-105.17 of this Act to help identify the value
12 of distributed energy resources for the purpose of
13 calculating the compensation described in this subsection.

14 (6) The Commission shall determine additional
15 compensation for distributed energy resources that creates
16 savings and value on the distribution system by being
17 co-located or in close proximity to electric vehicle
18 charging infrastructure in use by medium-duty and
19 heavy-duty vehicles, primarily serving environmental
20 justice communities, as outlined in the utility integrated
21 grid planning process under Section 16-105.17 of this Act.

22 No later than 60 days after the Commission enters its
23 final order under this subsection (e), each utility shall file
24 its updated tariff or tariffs in compliance with the order,
25 including new tariffs for the recovery of costs incurred under
26 this subsection (e) that shall provide for volumetric-based

1 cost recovery, and the Commission shall approve, or approve
2 with modification, the tariff or tariffs within 240 days after
3 the utility's filing.

4 (f) Notwithstanding any provision of this Act to the
5 contrary, the owner or operator of a community renewable
6 generation project as defined in Section 1-10 of the Illinois
7 Power Agency Act shall also be eligible to apply for the rebate
8 described in this Section. The owner or operator of the
9 community renewable generation project may apply for a rebate
10 only if the owner or operator, or previous owner or operator,
11 of the community renewable generation project has not already
12 submitted an application, and, regardless of whether the
13 subscriber is a residential or non-residential customer, may
14 be allowed the amount identified in paragraph (1) of
15 subsection (c) applicable on the date that the application is
16 submitted.

17 (g) The owner of the distributed generation or community
18 renewable generation project may apply for the rebate or
19 rebates approved under this Section at the time of execution
20 of an interconnection agreement with the distribution utility
21 and shall receive the value available at that time of
22 execution of the interconnection agreement, provided the
23 project reaches mechanical completion within 24 months after
24 execution of the interconnection agreement. If the project has
25 not reached mechanical completion within 24 months after
26 execution, the owner may reapply for the rebate or rebates

1 approved under this Section available at the time of
2 application and shall receive the value available at the time
3 of application. The utility shall issue the rebate no later
4 than 60 days after the project is energized. In the event the
5 application is incomplete or the utility is otherwise unable
6 to calculate the payment based on the information provided by
7 the owner, the utility shall issue the payment no later than 60
8 days after the application is complete or all requested
9 information is received.

10 (h) An electric utility shall recover from its retail
11 customers all of the costs of the rebates made under a tariff
12 or tariffs approved under subsection (d) of this Section,
13 including, but not limited to, the value of the rebates and all
14 costs incurred by the utility to comply with and implement
15 subsections (b) and (c) of this Section, but not including
16 costs incurred by the utility to comply with and implement
17 subsection (e) of this Section, consistent with the following
18 provisions:

19 (1) The utility shall defer the full amount of its
20 costs as a regulatory asset. The total costs deferred as a
21 regulatory asset shall be amortized over a 15-year period.
22 The unamortized balance shall be recognized as of December
23 31 for a given year. The utility shall also earn a return
24 on the total of the unamortized balance of the regulatory
25 assets, less any deferred taxes related to the unamortized
26 balance, at an annual rate equal to the utility's weighted

1 average cost of capital that includes, based on a year-end
2 capital structure, the utility's actual cost of debt for
3 the applicable calendar year and a cost of equity, which
4 shall be calculated as the sum of (i) the average for the
5 applicable calendar year of the monthly average yields of
6 30-year U.S. Treasury bonds published by the Board of
7 Governors of the Federal Reserve System in its weekly H.15
8 Statistical Release or successor publication; and (ii) 580
9 basis points, including a revenue conversion factor
10 calculated to recover or refund all additional income
11 taxes that may be payable or receivable as a result of that
12 return.

13 When an electric utility creates a regulatory asset
14 under the provisions of this paragraph (1) of subsection
15 (h), the costs are recovered over a period during which
16 customers also receive a benefit, which is in the public
17 interest. Accordingly, it is the intent of the General
18 Assembly that an electric utility that elects to create a
19 regulatory asset under the provisions of this paragraph
20 (1) shall recover all of the associated costs, including,
21 but not limited to, its cost of capital as set forth in
22 this paragraph (1). After the Commission has approved the
23 prudence and reasonableness of the costs that comprise the
24 regulatory asset, the electric utility shall be permitted
25 to recover all such costs, and the value and
26 recoverability through rates of the associated regulatory

1 asset shall not be limited, altered, impaired, or reduced.
2 To enable the financing of the incremental capital
3 expenditures, including regulatory assets, for electric
4 utilities that serve less than 3,000,000 retail customers
5 but more than 500,000 retail customers in the State, the
6 utility's actual year-end capital structure that includes
7 a common equity ratio, excluding goodwill, of up to and
8 including 50% of the total capital structure shall be
9 deemed reasonable and used to set rates.

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

1 including a revenue conversion factor calculated to
2 recover or refund all additional income taxes that may be
3 payable or receivable as a result of that return, of the
4 revenue requirement reflected in rates for each calendar
5 year, beginning with the calendar year in which the
6 utility files its automatic adjustment clause tariff under
7 this subsection (h), with what the revenue requirement
8 would have been had the actual cost information for the
9 applicable calendar year been available at the filing
10 date. The Commission shall review the proposed tariff and
11 may make changes to the tariff that are consistent with
12 this Section and with the Commission's authority under
13 Article IX of this Act, subject to notice and hearing.
14 Following notice and hearing, the Commission shall issue
15 an order approving, or approving with modification, such
16 tariff no later than 240 days after the utility files its
17 tariff.

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

25 (1) The utility may defer a portion of its costs as a
26 regulatory asset. The Commission shall determine the

1 portion that may be appropriately deferred as a regulatory
2 asset. Factors that the Commission shall consider in
3 determining the portion of costs that shall be deferred as
4 a regulatory asset include, but are not limited to: (i)
5 whether and the extent to which a cost effectively
6 deferred or avoided other distribution system operating
7 costs or capital expenditures; (ii) the extent to which a
8 cost provides environmental benefits; (iii) the extent to
9 which a cost improves system reliability or resilience;
10 (iv) the electric utility's distribution system plan
11 developed pursuant to Section 16-105.17 of this Act; (v)
12 the extent to which a cost advances equity principles; and
13 (vi) such other factors as the Commission deems
14 appropriate. The remainder of costs shall be deemed an
15 operating expense and shall be recoverable if found
16 prudent and reasonable by the Commission.

17 The total costs deferred as a regulatory asset shall
18 be amortized over a 15-year period. The unamortized
19 balance shall be recognized as of December 31 for a given
20 year. The utility shall also earn a return on the total of
21 the unamortized balance of the regulatory assets, less any
22 deferred taxes related to the unamortized balance, at an
23 annual rate equal to the utility's weighted average cost
24 of capital that includes, based on a year-end capital
25 structure, the utility's actual cost of debt for the
26 applicable calendar year and a cost of equity, which shall

1 be calculated as the sum of: (I) the average for the
2 applicable calendar year of the monthly average yields of
3 30-year U.S. Treasury bonds published by the Board of
4 Governors of the Federal Reserve System in its weekly H.15
5 Statistical Release or successor publication; and (II) 580
6 basis points, including a revenue conversion factor
7 calculated to recover or refund all additional income
8 taxes that may be payable or receivable as a result of that
9 return.

10 (2) The utility may recover all of the costs through
11 an automatic adjustment clause tariff, on a volumetric
12 basis. The utility may file its proposed cost-recovery
13 tariff together with the tariff it files under subsection
14 (e) of this Section or at a later time. The proposed tariff
15 shall provide for an annual reconciliation, less any
16 deferred taxes related to the reconciliation, with
17 interest at an annual rate of return equal to the
18 utility's weighted average cost of capital as calculated
19 under paragraph (1) of this subsection (i), including a
20 revenue conversion factor calculated to recover or refund
21 all additional income taxes that may be payable or
22 receivable as a result of that return, of the revenue
23 requirement reflected in rates for each calendar year,
24 beginning with the calendar year in which the utility
25 files its automatic adjustment clause tariff under this
26 subsection (i), with what the revenue requirement would

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

11 (j) No later than 90 days after the Commission enters an
12 order, or order on rehearing, whichever is later, approving an
13 electric utility's proposed tariff under this Section, the
14 electric utility shall provide notice of the availability of
15 rebates under this Section.

16 (Source: P.A. 102-662, eff. 9-15-21; 102-1031, eff. 5-27-22;
17 103-1066, eff. 2-20-25.)

18 (Text of Section after amendment by P.A. 104-458)

19 Sec. 16-107.6. Distributed generation and storage rebate.

20 (a) In this Section:

21 "Additive services" means the services that distributed
22 energy resources provide to the energy system and society that
23 are described in Section 16-107.9.

24 "Distributed energy resource" means a wide range of
25 technologies that are located on the customer side of the

1 customer's electric meter, including, but not limited to,
2 distributed generation, energy storage, electric vehicles, and
3 demand response technologies.

4 "Distributed storage" means energy storage systems that
5 are interconnected behind the customer's meter to the
6 distribution system or interconnected behind the storage
7 system's own meter to the distribution system.

8 "Energy storage system" means commercially available
9 technology that is capable of absorbing energy and storing it
10 for a period of time for use at a later time, including, but
11 not limited to, electrochemical, thermal, and
12 electromechanical technologies, and may be interconnected
13 behind the customer's meter or interconnected behind its own
14 meter.

15 "Smart inverter" means a device that converts direct
16 current into alternating current and meets the IEEE 1547-2018
17 equipment standards. Until devices that meet the IEEE
18 1547-2018 standard are available, devices that meet the UL
19 1741 SA standard are acceptable.

20 "Stand-alone energy storage system" means an energy
21 storage system that (i) is not paired with distributed
22 generation and (ii) has a nameplate capacity no greater than
23 5,000 kilowatt.

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

26 "Subscription" has the meaning set forth in Section 1-10

1 of the Illinois Power Agency Act.

2 "System-wide grid services" means the benefits that a
3 distributed energy resource provides to the distribution grid
4 for a period of no less than 25 years. System-wide grid
5 services do not vary by location, time, or the performance
6 characteristics of the distributed energy resource.
7 System-wide grid services include, but are not limited to,
8 avoided or deferred distribution capacity costs, resilience
9 and reliability benefits, avoided or deferred distribution
10 operation and maintenance costs, distribution voltage and
11 power quality benefits, and line loss reductions.

12 "Threshold date" means the date 2 years after the
13 effective date of this amendatory Act of the 104th General
14 Assembly or the date on which the utility's tariff or tariffs
15 authorized by Section 16-107.9 take effect, whichever is
16 later.

17 (b) An electric utility that serves more than 200,000
18 customers in the State shall file a petition with the
19 Commission requesting approval of the utility's tariff to
20 provide a rebate to the owner or operator of distributed
21 generation or distributed storage, including third-party owned
22 systems, that meets the following criteria:

23 (1) has a nameplate ~~generating~~ capacity no greater
24 than 5,000 kilowatts and is primarily used to offset a
25 customer's electricity load, or as otherwise as defined
26 for community renewable generation projects in Section

1 1-10 of the Illinois Power Agency Act;

2 (2) is located on the customer's side of the billing
3 meter and for the customer's own use;

4 (3) is interconnected to electric distribution
5 facilities owned by the electric utility under rules
6 adopted by the Commission by means of one or more
7 inverters or smart inverters required by this Section, as
8 applicable.

9 For purposes of this Section, "distributed generation"
10 shall satisfy the definition of distributed renewable energy
11 generation device set forth in Section 1-10 of the Illinois
12 Power Agency Act to the extent such definition is consistent
13 with the requirements of this Section.

14 In addition, any new photovoltaic distributed generation
15 that is installed after June 1, 2017 (the effective date of
16 Public Act 99-906) must be installed by a qualified person, as
17 defined by subsection (i) of Section 1-56 of the Illinois
18 Power Agency Act.

19 The tariff shall include a base rebate that compensates
20 distributed generation for the system-wide grid services
21 associated with distributed generation and an additional
22 payment or payments for any additive services identified by
23 the Commission under Section 16-107.9. The distributed
24 generation and storage tariff shall provide that the smart
25 inverter or smart inverters associated with the distributed
26 generation shall provide autonomous response to grid

1 conditions through its default settings as approved by the
2 Commission. Default settings may not be changed after the
3 execution of the interconnection agreement except by mutual
4 agreement between the utility and the owner or operator of the
5 distributed generation. Nothing in this Section shall negate
6 or supersede Institute of Electrical and Electronics Engineers
7 equipment standards or other similar standards or
8 requirements. The tariff shall not limit the ability of the
9 smart inverter or smart inverters or other distributed energy
10 resource to provide wholesale market products such as
11 regulation, demand response, or other services, or limit the
12 ability of the owner of the smart inverter or the other
13 distributed energy resource to receive compensation for
14 providing those wholesale market products or services.

15 (b-5) Within 30 days after the effective date of this
16 amendatory Act of the 102nd General Assembly, each electric
17 public utility with 3,000,000 or more retail customers shall
18 file a tariff with the Commission that further compensates any
19 retail customer that installs or has installed photovoltaic
20 facilities paired with energy storage facilities on or
21 adjacent to its premises for the benefits the facilities
22 provide to the distribution grid. The tariff shall provide
23 that, in addition to the other rebates identified in this
24 Section, the electric utility shall rebate to such retail
25 customer (i) the previously incurred and future costs of
26 installing interconnection facilities and related

1 infrastructure to enable full participation in the PJM
2 Interconnection, LLC or its successor organization frequency
3 regulation market; and (ii) all wholesale demand charges
4 incurred after the effective date of this amendatory Act of
5 the 102nd General Assembly. The Commission shall approve, or
6 approve with modification, the tariff within 120 days after
7 the utility's filing.

8 To be eligible for a rebate described in this subsection
9 (b-5), the owner or operator of the distributed generation
10 shall provide proof of participation in the frequency
11 regulation market. Upon providing proof of participation, the
12 retail customer shall be entitled to a rebate equal to the cost
13 of the interconnection facilities paid to ComEd, regardless of
14 whether the retail customer would have incurred the
15 interconnection costs in the absence of participating in the
16 frequency regulation market, plus the cost of software,
17 telecommunications hardware, and telemetry paid to enable
18 communication with PJM for purposes of participating in the
19 frequency regulation market. A utility providing rebates
20 described in this subsection (b-5) shall be entitled to
21 recover the costs of the rebates as provided for in subsection
22 (h) of this Section. To the extent the electric utility's
23 tariff is modified to comply with this subsection (b-5), it
24 shall file a revised tariff with the Commission within 120
25 days after the effective date of this amendatory Act of the
26 104th General Assembly, and the Commission shall approve, or

1 approve with modification, the tariff within 240 days after
2 the Commission initiates the docket.

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

8 (1) The owner or operator of distributed generation or
9 distributed storage that services customers not eligible
10 for net metering under subsection (d), (d-5), or (e) of
11 Section 16-107.5 of this Act may apply for a rebate as
12 provided for in this Section. The value of the rebate
13 shall be \$250 per kilowatt of nameplate generating
14 capacity, measured as nominal DC power output, of that
15 customer's distributed generation. To the extent the
16 distributed generation also has an associated energy
17 storage, then until the threshold date for systems other
18 than community renewable generation projects paired with
19 an energy storage system, the energy storage system shall
20 be separately compensated with a rebate of \$250 per
21 kilowatt-hour of nameplate capacity. To the extent that a
22 community renewable generation project is paired with an
23 energy storage system or an energy storage system that is
24 paired with distributed generation, the energy storage
25 system shall be separately compensated with a rebate of
26 \$250 per kilowatt-hour of nameplate capacity. A

1 stand-alone energy storage system shall be compensated
2 with a rebate of \$250 per kilowatt-hour of nameplate
3 capacity. Any distributed generation device that is
4 compensated for storage in this subsection (1) after the
5 effective date of this amendatory Act of the 104th General
6 Assembly shall participate in one or more programs
7 authorized by paragraph (1) of subsection (e).
8 Compensation for any additive services shall be as
9 determined by the Commission in the proceeding described
10 in Section 16-107.9. To the extent that an electric
11 utility's tariffs are inconsistent with the requirements
12 of this paragraph (1) as modified by this amendatory Act
13 of the 104th General Assembly, the electric utility shall,
14 within 60 days after the effective date of this amendatory
15 Act of the 104th General Assembly, file modified tariffs
16 consistent with the requirements of this paragraph (1). If
17 the Commission chooses to suspend the modified tariffs
18 following notice and hearing, the Commission shall issue
19 an order approving, or approving with modification, the
20 modified tariffs no later than 90 days after the
21 Commission initiates the docket.

22 (2) The owner or operator of distributed generation
23 that, before January 1, 2025 ~~the threshold date~~, would
24 have been eligible for net metering under subsection (d),
25 (d-5), or (e) of Section 16-107.5 of this Act and that has
26 not previously received a distributed generation rebate,

1 may apply for a rebate as provided for in this Section.
2 Until December 31, 2029, the value of the base rebate
3 shall be \$300 per kilowatt of nameplate generating
4 capacity, measured as nominal DC power output, of the
5 distributed generation. On or after January 1, 2030, the
6 value of the base rebate shall be \$250 per kilowatt of
7 nameplate generating capacity, measured as nominal DC
8 power output, of the distributed generation. The owner or
9 operator of distributed generation that, before January 1,
10 2025 ~~the threshold date~~, is eligible for net metering
11 under subsection (d), (d-5), or (e) of Section 16-107.5 of
12 this Act may apply for a base rebate for an associated
13 energy storage device behind the same retail customer
14 meter as the distributed generation, regardless of whether
15 the distributed generation applies for a rebate for the
16 distributed generation device. An energy storage system,
17 whether or not paired with distributed generation, shall
18 be separately compensated at a base payment of \$300 per
19 kilowatt-hour of nameplate capacity until the threshold
20 date. After the threshold date, a stand-alone energy
21 storage system that is neither paired with distributed
22 generation nor with any electric load beyond the electric
23 load that is used by the energy storage system itself
24 shall be compensated with a rebate of \$250 per
25 kilowatt-hour of nameplate capacity. Any distributed
26 generation device that is compensated for storage in this

1 subsection (2) has the option to participate in either an
2 hourly pricing program or time-of-use rate program and any
3 distributed generation device that is compensated for
4 storage in this subsection (2) after the effective date of
5 this amendatory Act of the 104th General Assembly shall
6 participate in a scheduled dispatch program set forth in
7 paragraph (1) of subsection (e) when it becomes available.
8 Compensation for any additive services or other programs
9 shall be as determined by the Commission in the proceeding
10 described in Section 16-107.9. To the extent that an
11 electric utility's tariffs are inconsistent with the
12 requirements of this paragraph (2) as modified by this
13 amendatory Act of the 104th General Assembly, such
14 electric utility shall, within 60 days, file modified
15 tariffs consistent with the requirements of this paragraph
16 (2).

17 (3) Upon approval of a rebate application submitted
18 under this subsection (c), the retail customer shall no
19 longer be entitled to receive any delivery service credits
20 for the excess electricity generated by its facility and
21 shall be subject to the provisions of subsection (n) of
22 Section 16-107.5 of this Act unless the owner or operator
23 receives a rebate only for an energy storage device and
24 not for the distributed generation device.

25 (4) To be eligible for a rebate described in this
26 subsection (c), the owner or operator of the distributed

1 generation must have a smart inverter installed and in
2 operation on the distributed generation.

3 (5) The owner or operator of any distributed
4 generation or distributed storage system whose electric
5 service has not been declared competitive under Section
6 16-113 as of July 1, 2011 or the owner or operator of a
7 community renewable generation project participating in
8 the Adjustable Block Program as a community-driven
9 community solar project as defined in item (v) of
10 subparagraph (K) of paragraph (1) of subsection (c) of
11 Section 1-75 of the Illinois Power Agency Act and that has
12 an interconnection agreement dated after the effective
13 date of this amendatory Act of the 104th General Assembly
14 shall be eligible for an additional payment or payments to
15 the applicable rebate under paragraphs (1) or (2) of this
16 subsection (c) in an amount set by tariff and approved by
17 the Commission if located in an equity investment eligible
18 community, as defined in Section 1-10 of the Illinois
19 Power Agency Act, at the time the interconnection
20 agreement is signed.

21 (d) The Commission shall review the proposed tariff
22 authorized by subsection (b) of this Section and may make
23 changes to the tariff that are consistent with this Section
24 and with the Commission's authority under Article IX of this
25 Act, subject to notice and hearing. Following notice and
26 hearing, the Commission shall issue an order approving, or

1 approving with modification, such tariff no later than 240
2 days after the utility files its tariff. Upon the effective
3 date of this amendatory Act of the 102nd General Assembly, an
4 electric utility shall file a petition with the Commission to
5 amend and update any existing tariffs to comply with
6 subsections (b) and (c).

7 (e) By no later than June 30, 2026, the Commission shall
8 establish a scheduled dispatch virtual power plant program in
9 which customers that own or operate an energy storage system
10 that receive a rebate for the distributed storage portion
11 under paragraphs (1) and (2) of subsection (c) are required to
12 participate.

13 (1) The scheduled dispatch virtual power plant program
14 shall require an enrollment period of 5 years and require
15 each participating system to commit to dispatch each
16 weekday during the months of June, July, August, and
17 September from 4 p.m. to 6 p.m. for systems interconnected
18 behind the meter of a retail customer and from 4 p.m. to 7
19 p.m. for systems interconnected on the distribution system
20 of an electric utility and not behind the meter of a retail
21 customer. For stand-alone storage that is neither paired
22 with distributed generation nor with any electric load
23 beyond the electric load that is used by the energy
24 storage system itself, commitments to dispatch shall be
25 voluntary. Upon petition by the applicable electric
26 utility or on its own motion, the Commission may approve

1 different dispatch schedules provided that dispatch events
2 do not exceed 80 days and shall not exceed 2 hours for
3 systems interconnected behind the meter of a retail
4 customer or 3 hours for systems interconnected on the
5 distribution system of an electric utility and not behind
6 the meter of a retail customer.

7 (2) The scheduled dispatch virtual power plant program
8 shall be open to all customer classes with eligible
9 distributed energy resources and shall measure performance
10 based on combined export of paired resources if the
11 eligible device is inverter-based renewables paired with
12 storage through at least December 31, 2030 and until the
13 Commission approves and the utility implements a tariff
14 under subsection (d) of Section 16-107.9 of this Act, at
15 which time such customers shall be transitioned to that
16 tariff in a manner prescribed in the tariff. The scheduled
17 dispatch virtual power plant program shall be required for
18 all community renewable generation projects paired with
19 distributed energy resources without regard to the
20 threshold date.

21 (3) Compensation shall be set by the Commission but
22 shall not be less than \$10 per kilowatt of average
23 dispatch during identified hours, paid to enrolled
24 customers or project owners at end of program year. For
25 distributed generation interconnected to an electric
26 utility's distribution system and not behind the meter of

1 a retail customer, dispatch to determine compensation
2 shall be measured at point of interconnection. For
3 distributed generation and storage interconnected behind
4 the meter of a retail customer, dispatch to determine
5 compensation shall be measured at the inverter connected
6 to the storage device.

7 (4) No later than June 1, 2026, each public utility
8 shall file an initial scheduled dispatch virtual power
9 plant tariff. The Commission shall approve, or approve
10 with modifications, the initial scheduled dispatch virtual
11 power plant tariff for each utility not later than June
12 30, 2026.

13 (5) The Commission, by its own motion or by petition
14 by an electric utility, may establish other additive
15 services programs in addition to the virtual power plant
16 program under Section 16-107.9. Nothing in this Section is
17 intended to preempt or delay the implementation of other
18 utility programs for devices that are not a part of the
19 scheduled dispatch virtual power plant program that the
20 Commission or utility may propose or require.

21 (6) No later than December 31, 2028, the utilities
22 shall file with the Commission a report that includes
23 information on the following: (A) the number of
24 participants in the scheduled dispatch program; (B)
25 impacts to energy supply prices and wholesale market
26 activities; (C) impacts on distribution system investments

1 and planning; and (D) any potential pathways by which the
2 virtual power plan program described in Section 16-107.9
3 may be designed to capture wholesale market value through
4 participation in the wholesale market and apply that
5 wholesale market revenue to reduce utility distribution or
6 electric supply rates for customers.

7 (f) Notwithstanding any provision of this Act to the
8 contrary, the owner or operator of a community renewable
9 generation project as defined in Section 1-10 of the Illinois
10 Power Agency Act whether or not a paired energy storage system
11 or the owner or operator of an energy storage system that is
12 eligible for net metering under subsection (1-10) of Section
13 16-107.5 shall also be eligible to apply for the rebate
14 described in this Section. The owner or operator of the
15 community renewable generation project whether or not a paired
16 energy storage system or the owner or operator of an energy
17 storage system that is eligible for net metering under
18 subsection (1-10) of Section 16-107.5 may apply for a rebate
19 only if the owner or operator, or previous owner or operator,
20 of the community renewable generation project whether or not a
21 paired energy storage system or the owner or operator of an
22 energy storage system that is eligible for net metering under
23 subsection (1-10) of Section 16-107.5 has not already
24 submitted an application, and, regardless of whether the
25 subscriber is a residential or non-residential customer, may
26 be allowed the amount identified in paragraph (1) of

1 subsection (c) applicable on the date that the application is
2 submitted.

3 (g) The owner of a distributed storage system, whether or
4 not paired with distributed generation, may apply for the
5 rebate or rebates approved under this Section at the time of
6 execution of an interconnection agreement with the
7 distribution utility and shall receive the value available at
8 that time of execution of the interconnection agreement. The
9 utility shall issue the rebate no later than 60 days after the
10 project is energized. In the event the application is
11 incomplete or the utility is otherwise unable to calculate the
12 payment based on the information provided by the owner, the
13 utility shall issue the payment no later than 60 days after the
14 application is complete or all requested information is
15 received.

16 (h) An electric utility shall recover from its retail
17 customers all of the costs of the rebates made under a tariff
18 or tariffs approved under this Section, including, but not
19 limited to, the value of the rebates and all costs incurred by
20 the utility to comply with and implement subsections (b),
21 (b-5), (c), and (e) of this Section, consistent with the
22 following provisions:

23 (1) The utility shall defer the full amount of its
24 costs as a regulatory asset. The total costs deferred as a
25 regulatory asset shall be amortized over a 15-year period.
26 The unamortized balance shall be recognized as of December

1 31 for a given year. The utility shall also earn a return
2 on the total of the unamortized balance of the regulatory
3 assets, less any deferred taxes related to the unamortized
4 balance, at an annual rate equal to the utility's weighted
5 average cost of capital that includes, based on a year-end
6 capital structure, the utility's actual cost of debt for
7 the applicable calendar year and a cost of equity, which
8 shall be equal to the baseline cost of equity approved by
9 the Commission for the utility's electric distribution
10 rates case effective during the applicable year, whether
11 those rates are set pursuant to Section 9-201,
12 subparagraph (B) of paragraph (3) of subsection (d) of
13 Section 16-108.18, or any successor electric distribution
14 ratemaking paradigm.

15 When an electric utility creates a regulatory asset
16 under the provisions of this paragraph (1) of subsection
17 (h), the costs are recovered over a period during which
18 customers also receive a benefit, which is in the public
19 interest. Accordingly, it is the intent of the General
20 Assembly that an electric utility that elects to create a
21 regulatory asset under the provisions of this paragraph
22 (1) shall recover all of the associated costs, including,
23 but not limited to, its cost of capital as set forth in
24 this paragraph (1). After the Commission has approved the
25 prudence and reasonableness of the costs that comprise the
26 regulatory asset, the electric utility shall be permitted

1 to recover all such costs, and the value and
2 recoverability through rates of the associated regulatory
3 asset shall not be limited, altered, impaired, or reduced.
4 To enable the financing of the incremental capital
5 expenditures, including regulatory assets, for electric
6 utilities that serve less than 3,000,000 retail customers
7 but more than 500,000 retail customers in the State, the
8 utility's actual year-end capital structure that includes
9 a common equity ratio, excluding goodwill, of up to and
10 including 50% of the total capital structure shall be
11 deemed reasonable and used to set rates.

12 (2) The utility, at its election, may recover all of
13 the costs as part of a filing for a general increase in
14 rates under Article IX of this Act, as part of an annual
15 filing to update a performance-based rate under Section
16 16-108.18, or through an automatic adjustment clause
17 tariff, provided that nothing in this paragraph (2)
18 permits the double recovery of such costs from customers.
19 If the utility elects to recover the costs it incurs under
20 subsections (b), (b-5), (c), and (e) through an automatic
21 adjustment clause tariff, the utility may file its
22 proposed tariff together with the tariff it files under
23 subsection (b) of this Section or at a later time. The
24 proposed tariff shall provide for an annual
25 reconciliation, less any deferred taxes related to the
26 reconciliation, with interest at an annual rate of return

1 equal to the utility's weighted average cost of capital as
2 calculated under paragraph (1) of this subsection (h),
3 including a revenue conversion factor calculated to
4 recover or refund all additional income taxes that may be
5 payable or receivable as a result of that return, of the
6 revenue requirement reflected in rates for each calendar
7 year, beginning with the calendar year in which the
8 utility files its automatic adjustment clause tariff under
9 this subsection (h), with what the revenue requirement
10 would have been had the actual cost information for the
11 applicable calendar year been available at the filing
12 date. The Commission shall review the proposed tariff and
13 may make changes to the tariff that are consistent with
14 this Section and with the Commission's authority under
15 Article IX of this Act, subject to notice and hearing.
16 Following notice and hearing, the Commission shall issue
17 an order approving, or approving with modification, such
18 tariff no later than 240 days after the utility files its
19 tariff.

20 (i) (Blank).

21 (j) No later than 90 days after the Commission enters an
22 order, or order on rehearing, whichever is later, approving an
23 electric utility's proposed tariff under this Section, the
24 electric utility shall provide notice of the availability of
25 rebates under this Section.

26 (k) No later than January 1, 2030, the utilities shall

1 file with the Commission a report that includes:

2 (1) the number and geographic distribution of
3 participants receiving rebates pursuant to this Section;

4 (2) impacts to energy supply prices and wholesale
5 market activities;

6 (3) impacts on distribution system investments and
7 planning; and

8 (4) any other values deemed relevant by the
9 Commission.

10 (1) Upon petition by the applicable electric utility or on
11 its own motion, the Commission may adjust rebate levels for
12 new customers and make other appropriate changes to the rebate
13 program in a manner that is consistent with the State's clean
14 energy goals and the public interest.

15 (Source: P.A. 103-1066, eff. 2-20-25; 104-458, eff. 6-1-26.)

16 (220 ILCS 5/16-107.9)

17 (This Section may contain text from a Public Act with a
18 delayed effective date)

19 Sec. 16-107.9. Virtual power plant program.

20 (a) As used in this Section:

21 "Aggregator" means a third-party entity that participates
22 in the program, other than the electric utility or its
23 affiliate, that (i) represents and aggregates the load of
24 participating customers who collectively have the ability to
25 deploy 100 kilowatts or more of deployment of eligible devices

1 and (ii) is responsible for performance of the aggregation in
2 the program.

3 "Battery" means a behind-the-meter energy storage device
4 and associated equipment that operate together to fulfill
5 program requirements.

6 "Commission" means the Illinois Commerce Commission.

7 "Customer" means an active electric service account holder
8 of a utility.

9 "Direct participant" means a customer that enrolls in the
10 program directly with the utility, rather than participating
11 in the program through an aggregator.

12 "Distributed energy resource" has the meaning set forth in
13 Section 16-107.6.

14 "Distributed energy resources management system" means a
15 platform that may be used by distribution system operators or
16 utilities to integrate grid resources, such as distributed
17 energy resources, into system operations.

18 "Eligible device" means a customer or third party-owned
19 distributed energy resource that satisfies the requirements
20 for participation in the program as specified in the relevant
21 program rider. "Eligible device" also means any device that
22 can be controlled to respond to pricing, provide services,
23 including decrease peak electricity demand or shift demand
24 from peak to off-peak periods, or inject power to the grid.
25 "Eligible device" includes, but is not limited to,
26 behind-the-meter energy storage systems, smart thermostats,

1 electric vehicle batteries, including fleets, and distributed
2 renewable energy devices paired with one or more energy
3 storage systems.

4 "Emergency event" means an event called by the utility
5 with fewer than 24 hours notice.

6 "Energy storage system" has the meaning set forth in
7 subsection (a) of Section 16-107.6.

8 "Enrolled customer" means a customer that participates in
9 the program through either an aggregator or as a direct
10 participant.

11 "Enrolled device" means an enrolled customer's eligible
12 device, as specified in the relevant tariff.

13 "Enterprise distributed energy resources management
14 system" means a platform operated by the electric utility that
15 interfaces with a grid-edge distributed energy resources
16 management system to integrate distributed energy resources
17 into utility electric system operations.

18 "Grid-edge distributed energy resources management system"
19 means a platform owned by a party other than the electric
20 utility that may be used to integrate distributed energy
21 resources.

22 "Grid event" means a grid condition for which the utility
23 schedules or remotely dispatches enrolled devices to respond
24 to, as specified in the grid service opportunities for each
25 tariff.

26 "Grid service" means a capacity, energy, or ancillary

1 service that supports grid operations.

2 "Participating customer" means an aggregator or a direct
3 retail customer, as defined in Section 16-102, with one or
4 more eligible devices.

5 "Performance payment" means a payment made to the
6 participant based on the performance of an enrolled device
7 providing a grid service during a grid event.

8 "Performance payment rate" means the compensation rate
9 paid to participants for providing a particular grid service
10 during a grid event.

11 "Smart inverter" has the meaning set forth in subsection
12 (a) of Section 16-107.6.

13 "Upfront payment" means a one-time payment made at the
14 time of enrollment.

15 "Virtual power plant" means an aggregation of
16 behind-the-meter distributed energy resources operated in
17 coordination to provide one or more grid services.

18 (b) The General Assembly finds that:

19 (1) virtual power plants are dynamic load management
20 and energy supply resources that can support grid
21 operations, reduce ratepayer costs, and achieve other
22 important public policy goals;

23 (2) virtual power plants can reduce demand for grid
24 supplied electricity during peak periods, shift
25 electricity consumption out of peak periods, make
26 renewable energy generated during off-peak periods

1 available for use during peak periods, supply energy to
2 the grid at desired times, provide frequency regulation,
3 voltage support, and other ancillary services, reduce
4 strain on the distribution system, manage localized peaks,
5 improve system resiliency and reliability, and provide
6 other grid services;

7 (3) virtual power plants can facilitate and optimize
8 the utilization of electrical generation from wind and
9 solar energy to help utilities increase hosting capacity
10 and integrate more renewable energy resources;

11 (4) virtual power plants can reduce costs to
12 ratepayers by utilizing customer-sited resources to
13 provide grid services, avoiding or reducing reliance on
14 fossil-fuel fired peaker plants, avoiding or deferring the
15 need to construct new and more costly grid scale
16 resources, optimizing the use of existing assets, and
17 avoiding or deferring distribution and transmission system
18 upgrades and other grid investments;

19 (5) virtual power plants can promote equity by
20 reducing costs for all ratepayers, expanding access to
21 distributed energy resources among low-income and
22 moderate-income customers through improved distributed
23 energy resource finance ability, and providing other
24 important co-benefits, including reduction in emissions of
25 greenhouse gases and other pollutants, especially in
26 environmental justice and other disadvantaged communities

1 that host fossil fuel generation plants;

2 (6) the United States Department of Energy estimates
3 that the United States could deploy 80 to 160 gigawatts of
4 virtual power plants by 2030, a tripling of current
5 levels, to support the rapid electrification of vehicles
6 and homes and provide on the order of \$10,000,000,000 in
7 ratepayer savings annually. The deployment of virtual
8 power plants can provide energy cost savings and other
9 benefits to the people of Illinois;

10 (7) there are significant barriers to deployment and
11 operation of virtual power plants, including the need for
12 statutory and regulatory guidance and support, greater
13 consistency in virtual power plant programs across
14 regulatory jurisdictions, and for utility commitments to
15 incorporate the use of virtual power plants into system
16 operations and long-term resource planning;

17 (8) it is in the public interest to advance customer
18 choice and leverage the expertise of private, non-utility
19 entities to advance innovation and implement
20 cost-effective clean energy solutions; and

21 (9) the policy of Illinois shall be to maximize the
22 use of virtual power plants comprised of customer-owned
23 and third party-owned distributed energy resources to
24 deliver system services and other benefits through utility
25 administered virtual power plant programs in accordance
26 with the provisions of this amendatory Act of the 104th

1 General Assembly.

2 (c) No later than December 31, 2028, the Commission shall
3 approve at least one virtual power plant tariff for each
4 electric utility serving more than 300,000 customers in the
5 State as of January 1, 2023. Each utility shall file a tariff
6 or tariffs for approval no later than December 31, 2027 to
7 allow retail customers in the electric utility's service areas
8 to participate in a virtual power plant program proposal
9 consistent with the provisions of this Section. The Commission
10 shall provide opportunities for stakeholders to provide input
11 on the virtual power plant programs proposed for
12 implementation by each utility, which the Commission shall
13 take into consideration in its review of each utility's
14 filing. No later than one year after the utility's filing, the
15 Commission shall approve or modify and approve each utility's
16 virtual power plant program proposal for immediate
17 implementation by the utility.

18 (d) The virtual power plant program filed under subsection
19 (c) shall be developed for implementation through a tariff
20 offering with standard terms and conditions for participation.
21 The virtual power plant program tariff shall allow for
22 customers with battery storage, non-battery storage and
23 electric vehicle technologies to enroll the devices in the
24 program through aggregators or directly with the utility. The
25 virtual power plant program tariff shall:

26 (1) provide a mechanism to incorporate existing

1 programs, such as smart thermostat demand-response or
2 electric vehicle charging programs or behavioral
3 demand-response programs currently offered by the utility,
4 under the virtual power plant program framework;

5 (2) provide grid services opportunities for each
6 eligible technology that customers and aggregators may
7 provide, which shall include, at minimum, reducing the
8 utility's applicable capacity and transmission obligations
9 and capturing daily wholesale energy arbitrage
10 opportunities through provision of grid services;

11 (3) provide additional functions and grid service
12 opportunities that the Commission determines are
13 supportive of efficient planning and operation of the
14 electrical grid, including:

15 (A) minimizing the use of fossil fuels at peak
16 times;

17 (B) local peak demand reductions;

18 (C) locational value;

19 (D) the avoidance or deferral of local
20 transmission or distribution upgrades or capacity
21 expansion;

22 (E) voltage support and other ancillary services;

23 and

24 (F) emergency grid services;

25 (4) provide operational parameters, which shall
26 include, at a minimum:

1 (A) minimum and maximum numbers of grid events for
2 which the utility may require dispatch from the
3 enrolled distributed energy resources;

4 (B) months of the year that grid events may occur;

5 (C) days of the week that grid events may occur;

6 (D) times of day that grid events may occur;

7 (E) maximum duration of grid events; and

8 (F) minimum day-ahead advance notification
9 requirement of grid events, except for emergency
10 events, as applicable;

11 (5) include provisions for aggregators to participate
12 in the virtual power plant program, participate in the
13 utility's distributed energy resource management system as
14 available, automatically enroll and manage their
15 customers' participation, receive dispatch signals and
16 other communications from the utility, deliver performance
17 measurement and verification data to the utility, and
18 receive virtual power plant program payments directly from
19 the utility;

20 (6) include provisions that provide a standardized
21 process for any eligible aggregator to enroll in the
22 program and authorize the eligible aggregators to manage
23 individual customer device participation without
24 additional authorizations from the utility;

25 (7) include provisions that allow a participating
26 customer with multiple eligible devices to enroll the

1 technologies either directly without an aggregator or
2 through one or more aggregators in applicable programs
3 under the tariff approved under this Section, provided
4 that no particular device is accounted for more than once;

5 (8) include provisions for direct participant
6 customers to participate with the utility's distributed
7 energy resource management system as available, receive
8 dispatch signals and other communications from the
9 utility, deliver performance measurement and verification
10 data to the utility, and receive virtual power plant
11 program payments directly from the utility. Any provisions
12 implementing this subpart that necessitate the
13 installation of equipment to enable direct participation
14 via the utility shall apply to customers who elect to
15 participate as a direct participant and shall not be
16 required of customers who participate via an aggregator or
17 to customers who do not participate in the virtual power
18 plant program;

19 (9) provide for measurement and verification of
20 battery non-battery, and electric vehicle technologies
21 performance directly at the device without the requirement
22 for the installation of an additional meter;

23 (10) include upfront payment or performance payment
24 compensation mechanisms for the peak reduction service, as
25 well as for non-battery and electric vehicle technologies
26 as the Commission deems appropriate. The performance

1 payment shall be based on the average capacity provided
2 during grid events. The Commission shall approve
3 additional compensation mechanisms as it determines
4 appropriate for other grid services provided under the
5 battery, non-battery and electric vehicle riders. The
6 virtual power plant program shall not assess penalties for
7 non-performance; provided, however, that the Commission
8 may approve reasonable mechanisms to disenroll customers
9 for continued non-performance;

10 (11) enable low-to-moderate income customers,
11 community-driven community solar projects, and customers
12 whose electric service has not been declared competitive
13 pursuant to Section 16-113 as of July 1, 2011 located in
14 equity investment eligible investment communities to
15 receive a higher upfront enrollment payment. The
16 Commission shall coordinate with State energy officials
17 and departments to make funding from federal programs and
18 such other sources as may be available for use in
19 providing higher upfront payments to customers classes as
20 may be approved by the Commission in accordance with this
21 subsection;

22 (12) provide that the performance payment rate
23 applicable at the time of enrollment shall be for 5 years,
24 after which time the participant may reenroll at the then
25 applicable performance payment rate for an additional
26 5-year term;

1 (13) provide for a transition of customers from the
2 scheduled dispatch program described in Section 16-107.6
3 to the virtual power plant program; and

4 (14) allow enrolled customers to participate in other
5 applicable interconnection tariffs and grid service
6 programs outside the virtual power plant program, so long
7 as it does not result in double-counting of benefits for
8 the same grid services.

9 (e) The Commission may adopt other reasonable requirements
10 for participation consistent with this subsection, provided
11 that collateral from an aggregator shall not be required for
12 participation.

13 (f) The utility may contract with a third party-owned
14 distributed energy resource management system provider to
15 assist with program implementation; however, implementation
16 shall not be delayed due to the lack of utility-owned
17 distributed energy resource management system capabilities or
18 third party-owned distributed energy resource management
19 system capabilities.

20 (g) The utility shall not send or receive dispatch signals
21 directly to or from any participating customer represented by
22 an aggregator for an event under the virtual power plant
23 program described in this Section.

24 (h) Participating aggregators shall have capabilities to
25 receive event signals from utilities or utility-contracted
26 distributed energy resources management system providers.

1 (i) Utilities shall recover reasonably and prudently
2 incurred costs to facilitate the virtual power plant program
3 approved under subsection (c), including, but not limited to,
4 distributed energy resource management systems provider and
5 other service contract costs, operations and maintenance
6 expenses, information technology costs, and other costs,
7 expenses, and investments that the Commission finds necessary
8 and prudent for the development and implementation of the
9 program. The utility shall recover the cost of virtual power
10 plant program upfront payments and performance payments and
11 such other payments made to participants through the tariff
12 filed pursuant to subsection (h) of Section 16-107.6.

13 (j) No later than January 31 of each year, each utility
14 shall file an annual report that includes, but is not limited
15 to:

16 (1) the total capacity enrolled in each program rider
17 developed in accordance with the requirements of Section,
18 broken down by technology type, customer class, and
19 aggregator and direct participant status for each grid
20 service opportunity offered in the prior calendar year;

21 (2) recommendations to increase participation in the
22 virtual power plant program; and

23 (3) any other information that the Commission may
24 require.

25 (k) Each utility shall amend existing tariffs and
26 procedures that limit the ability of customers to participate

1 in providing grid services under the program, such as
2 limitations on charging energy storage devices with grid
3 energy or exporting energy to the grid from battery discharge.

4 (l) The tariffs approved by the Commission shall not
5 reflect any additional charges, fees, or insurance
6 requirements imposed on those owning or operating
7 demand-response technologies beyond those imposed on similarly
8 situated customers that do not own or operate demand-response
9 technologies.

10 (m) As a condition of participating in the programs
11 described in this Section, prior to enrollment of a customer
12 by an aggregator, the aggregator shall disclose the following:

13 (1) the payments, expressed as an amount or a formula,
14 to be provided to the customer;

15 (2) between the aggregator and customer, who is
16 responsible for paying penalties or fees; and

17 (3) between the aggregator and customer, who is
18 responsible for posting collateral, if required.

19 Any tariff authorized by this Section shall incorporate
20 the requirements under this subsection and shall require the
21 electric utility to establish a complaint and Commission
22 notification process and, on order of the Commission, suspend
23 any aggregator repeatedly or egregiously violating such
24 requirements.

25 (Source: P.A. 104-458, eff. 6-1-26.)

1 Section 30. The Utility Data Access Act is amended by
2 changing Section 5-10 as follows:

3 (220 ILCS 33/5-10)

4 (This Section may contain text from a Public Act with a
5 delayed effective date)

6 Sec. 5-10. Definitions. As used in this Act:

7 "Account holder" or "customer" means the person or entity
8 authorized to access or modify utility account details.

9 "Aggregated usage data" means an aggregation of covered
10 usage data, where all data associated with a qualified
11 building or qualified property, including, but not limited to,
12 data from tenant meters and from owner meters, are combined
13 into one collective data point per utility data type, per time
14 period, and where any unique identifiers or other personal
15 information are removed or dissociated from individual meter
16 data.

17 "Aggregation threshold" means 3 or more unique
18 nonresidential qualified accounts or any combination of 5 or
19 more residential and nonresidential unique qualified accounts
20 of a property or building during the period for which data is
21 requested.

22 "Benchmarking tool" means the ENERGY STAR Portfolio
23 Manager web-based tool or any prudent and cost-effective
24 alternative system or tool approved by the Commission should
25 ENERGY STAR Portfolio Manager become inoperative or no longer

1 useful to achieving the policy goals of the State of Illinois
2 that (i) enables the periodic entry of a building's energy use
3 data and other descriptive information about a building and
4 (ii) rates a building's energy efficiency against that of
5 comparable buildings nationwide.

6 "Commission" means the Illinois Commerce Commission.

7 "Covered usage data" means electric data collected from
8 one or more utility meters that reflects the quantity and
9 period of utility usage in the building, property, or portion
10 thereof.

11 "Data recipient" means:

12 (1) an owner of the property or building;

13 (2) an owner of a portion of a property with regard to
14 covered usage data only for the utility consumption the
15 owner or the owner's tenants, if any, pay for and consume
16 in the owned portion;

17 (3) a tenant with regard to covered usage data only
18 for the utility consumption the tenant or the tenant's
19 subtenants, if any, pay for and consume in the space
20 leased by the tenant;

21 (4) the board, in the case of a condominium or
22 cooperative ownership of the property or building; or

23 (5) an agent authorized to receive the covered usage
24 data by anyone in paragraphs (1) through (4).

25 "Property" means:

26 (1) a single tax parcel;

1 (2) 2 or more tax parcels held in the cooperative or
2 condominium form of ownership and governed by a single
3 board of managers; or

4 (3) 2 or more colocated tax parcels owned or
5 controlled by the same entity.

6 "Qualified account" means a utility account that serves
7 some or all of a building or property for which covered usage
8 data is requested and that, as affirmed by the data recipient,
9 was not controlled by the data recipient or its subsidiary
10 during the time period for which covered usage data is
11 requested.

12 "Qualified building" means a building that meets the
13 aggregation threshold.

14 "Qualified data recipient" means a data recipient with
15 respect to a qualified property or qualified building.

16 "Qualified property" means a property that meets the
17 aggregation threshold.

18 "Utility" means an entity that is an electric or gas
19 utility with over 500,000 customers in this State and that is a
20 public utility, as defined in Section 3-105 of the Public
21 Utilities Act.

22 "Utility data type" means electric or gas.

23 (Source: P.A. 104-458, eff. 6-1-26.)

24 Section 35. The Environmental Protection Act is amended by
25 changing Section 9.15 as follows:

1 (415 ILCS 5/9.15)

2 (Text of Section before amendment by P.A. 104-458)

3 Sec. 9.15. Greenhouse gases.

4 (a) An air pollution construction permit shall not be
5 required due to emissions of greenhouse gases if the
6 equipment, site, or source is not subject to regulation, as
7 defined by 40 CFR 52.21, as now or hereafter amended, for
8 greenhouse gases or is otherwise not addressed in this Section
9 or by the Board in regulations for greenhouse gases. These
10 exemptions do not relieve an owner or operator from the
11 obligation to comply with other applicable rules or
12 regulations.

13 (b) An air pollution operating permit shall not be
14 required due to emissions of greenhouse gases if the
15 equipment, site, or source is not subject to regulation, as
16 defined by Section 39.5 of this Act, for greenhouse gases or is
17 otherwise not addressed in this Section or by the Board in
18 regulations for greenhouse gases. These exemptions do not
19 relieve an owner or operator from the obligation to comply
20 with other applicable rules or regulations.

21 (c) (Blank).

22 (d) (Blank).

23 (e) (Blank).

24 (f) As used in this Section:

25 "Carbon dioxide emission" means the plant annual CO₂ total

1 output emission as measured by the United States Environmental
2 Protection Agency in its Emissions & Generation Resource
3 Integrated Database (eGrid), or its successor.

4 "Carbon dioxide equivalent emissions" or "CO₂e" means the
5 sum total of the mass amount of emissions in tons per year,
6 calculated by multiplying the mass amount of each of the 6
7 greenhouse gases specified in Section 3.207, in tons per year,
8 by its associated global warming potential as set forth in 40
9 CFR 98, subpart A, table A-1 or its successor, and then adding
10 them all together.

11 "Cogeneration" or "combined heat and power" refers to any
12 system that, either simultaneously or sequentially, produces
13 electricity and useful thermal energy from a single fuel
14 source.

15 "Copollutants" refers to the 6 criteria pollutants that
16 have been identified by the United States Environmental
17 Protection Agency pursuant to the Clean Air Act.

18 "Electric generating unit" or "EGU" means a fossil
19 fuel-fired stationary boiler, combustion turbine, or combined
20 cycle system that serves a generator that has a nameplate
21 capacity greater than 25 MWe and produces electricity for
22 sale.

23 "Environmental justice community" means the definition of
24 that term based on existing methodologies and findings, used
25 and as may be updated by the Illinois Power Agency and its
26 program administrator in the Illinois Solar for All Program.

1 "Equity investment eligible community" or "eligible
2 community" means the geographic areas throughout Illinois that
3 would most benefit from equitable investments by the State
4 designed to combat discrimination and foster sustainable
5 economic growth. Specifically, eligible community means the
6 following areas:

7 (1) areas where residents have been historically
8 excluded from economic opportunities, including
9 opportunities in the energy sector, as defined as R3 areas
10 pursuant to Section 10-40 of the Cannabis Regulation and
11 Tax Act; and

12 (2) areas where residents have been historically
13 subject to disproportionate burdens of pollution,
14 including pollution from the energy sector, as established
15 by environmental justice communities as defined by the
16 Illinois Power Agency pursuant to the Illinois Power
17 Agency Act, excluding any racial or ethnic indicators.

18 "Equity investment eligible person" or "eligible person"
19 means the persons who would most benefit from equitable
20 investments by the State designed to combat discrimination and
21 foster sustainable economic growth. Specifically, eligible
22 person means the following people:

23 (1) persons whose primary residence is in an equity
24 investment eligible community;

25 (2) persons whose primary residence is in a
26 municipality, or a county with a population under 100,000,

1 where the closure of an electric generating unit or mine
2 has been publicly announced or the electric generating
3 unit or mine is in the process of closing or closed within
4 the last 5 years;

5 (3) persons who are graduates of or currently enrolled
6 in the foster care system; or

7 (4) persons who were formerly incarcerated.

8 "Existing emissions" means:

9 (1) for CO₂e, the total average tons-per-year of CO₂e
10 emitted by the EGU or large GHG-emitting unit either in
11 the years 2018 through 2020 or, if the unit was not yet in
12 operation by January 1, 2018, in the first 3 full years of
13 that unit's operation; and

14 (2) for any copollutant, the total average
15 tons-per-year of that copollutant emitted by the EGU or
16 large GHG-emitting unit either in the years 2018 through
17 2020 or, if the unit was not yet in operation by January 1,
18 2018, in the first 3 full years of that unit's operation.

19 "Green hydrogen" means a power plant technology in which
20 an EGU creates electric power exclusively from electrolytic
21 hydrogen, in a manner that produces zero carbon and
22 copollutant emissions, using hydrogen fuel that is
23 electrolyzed using a 100% renewable zero carbon emission
24 energy source.

25 "Large greenhouse gas-emitting unit" or "large
26 GHG-emitting unit" means a unit that is an electric generating

1 unit or other fossil fuel-fired unit that itself has a
2 nameplate capacity or serves a generator that has a nameplate
3 capacity greater than 25 MWe and that produces electricity,
4 including, but not limited to, coal-fired, coal-derived,
5 oil-fired, natural gas-fired, and cogeneration units.

6 "NO_x emission rate" means the plant annual NO_x total output
7 emission rate as measured by the United States Environmental
8 Protection Agency in its Emissions & Generation Resource
9 Integrated Database (eGrid), or its successor, in the most
10 recent year for which data is available.

11 "Public greenhouse gas-emitting units" or "public
12 GHG-emitting unit" means large greenhouse gas-emitting units,
13 including EGUs, that are wholly owned, directly or indirectly,
14 by one or more municipalities, municipal corporations, joint
15 municipal electric power agencies, electric cooperatives, or
16 other governmental or nonprofit entities, whether organized
17 and created under the laws of Illinois or another state.

18 "SO₂ emission rate" means the "plant annual SO₂ total
19 output emission rate" as measured by the United States
20 Environmental Protection Agency in its Emissions & Generation
21 Resource Integrated Database (eGrid), or its successor, in the
22 most recent year for which data is available.

23 (g) All EGUs and large greenhouse gas-emitting units that
24 use coal or oil as a fuel and are not public GHG-emitting units
25 shall permanently reduce all CO₂e and copollutant emissions to
26 zero no later than January 1, 2030.

1 (h) All EGUs and large greenhouse gas-emitting units that
2 use coal as a fuel and are public GHG-emitting units shall
3 permanently reduce CO₂e emissions to zero no later than
4 December 31, 2045. Any source or plant with such units must
5 also reduce their CO₂e emissions by 45% from existing
6 emissions by no later than January 1, 2035. If the emissions
7 reduction requirement is not achieved by December 31, 2035,
8 the plant shall retire one or more units or otherwise reduce
9 its CO₂e emissions by 45% from existing emissions by June 30,
10 2038.

11 (i) All EGUs and large greenhouse gas-emitting units that
12 use gas as a fuel and are not public GHG-emitting units shall
13 permanently reduce all CO₂e and copollutant emissions to zero,
14 including through unit retirement or the use of 100% green
15 hydrogen or other similar technology that is commercially
16 proven to achieve zero carbon emissions, according to the
17 following:

18 (1) No later than January 1, 2030: all EGUs and large
19 greenhouse gas-emitting units that have a NO_x emissions
20 rate of greater than 0.12 lbs/MWh or a SO₂ emission rate of
21 greater than 0.006 lb/MWh, and are located in or within 3
22 miles of an environmental justice community designated as
23 of January 1, 2021 or an equity investment eligible
24 community.

25 (2) No later than January 1, 2040: all EGUs and large
26 greenhouse gas-emitting units that have a NO_x emission

1 rate of greater than 0.12 lbs/MWh or a SO₂ emission rate
2 greater than 0.006 lb/MWh, and are not located in or
3 within 3 miles of an environmental justice community
4 designated as of January 1, 2021 or an equity investment
5 eligible community. After January 1, 2035, each such EGU
6 and large greenhouse gas-emitting unit shall reduce its
7 CO₂e emissions by at least 50% from its existing emissions
8 for CO₂e, and shall be limited in operation to, on average,
9 6 hours or less per day, measured over a calendar year, and
10 shall not run for more than 24 consecutive hours except in
11 emergency conditions, as designated by a Regional
12 Transmission Organization or Independent System Operator.

13 (3) No later than January 1, 2035: all EGUs and large
14 greenhouse gas-emitting units that began operation prior
15 to the effective date of this amendatory Act of the 102nd
16 General Assembly and have a NO_x emission rate of less than
17 or equal to 0.12 lb/MWh and a SO₂ emission rate less than
18 or equal to 0.006 lb/MWh, and are located in or within 3
19 miles of an environmental justice community designated as
20 of January 1, 2021 or an equity investment eligible
21 community. Each such EGU and large greenhouse gas-emitting
22 unit shall reduce its CO₂e emissions by at least 50% from
23 its existing emissions for CO₂e no later than January 1,
24 2030.

25 (4) No later than January 1, 2040: All remaining EGUs
26 and large greenhouse gas-emitting units that have a heat

1 rate greater than or equal to 7000 BTU/kWh. Each such EGU
2 and Large greenhouse gas-emitting unit shall reduce its
3 CO₂e emissions by at least 50% from its existing emissions
4 for CO₂e no later than January 1, 2035.

5 (5) No later than January 1, 2045: all remaining EGUs
6 and large greenhouse gas-emitting units.

7 (j) All EGUs and large greenhouse gas-emitting units that
8 use gas as a fuel and are public GHG-emitting units shall
9 permanently reduce all CO₂e and copollutant emissions to zero,
10 including through unit retirement or the use of 100% green
11 hydrogen or other similar technology that is commercially
12 proven to achieve zero carbon emissions by January 1, 2045.

13 (k) All EGUs and large greenhouse gas-emitting units that
14 utilize combined heat and power or cogeneration technology
15 shall permanently reduce all CO₂e and copollutant emissions to
16 zero, including through unit retirement or the use of 100%
17 green hydrogen or other similar technology that is
18 commercially proven to achieve zero carbon emissions by
19 January 1, 2045.

20 (k-5) No EGU or large greenhouse gas-emitting unit that
21 uses gas as a fuel and is not a public GHG-emitting unit may
22 emit, in any 12-month period, CO₂e or copollutants in excess of
23 that unit's existing emissions for those pollutants.

24 (l) Notwithstanding subsections (g) through (k-5), large
25 GHG-emitting units including EGUs may temporarily continue
26 emitting CO₂e and copollutants after any applicable deadline

1 specified in any of subsections (g) through (k-5) if it has
2 been determined, as described in paragraphs (1) and (2) of
3 this subsection, that ongoing operation of the EGU is
4 necessary to maintain power grid supply and reliability or
5 ongoing operation of large GHG-emitting unit that is not an
6 EGU is necessary to serve as an emergency backup to
7 operations. Up to and including the occurrence of an emission
8 reduction deadline under subsection (i), all EGUs and large
9 GHG-emitting units must comply with the following terms:

10 (1) if an EGU or large GHG-emitting unit that is a
11 participant in a regional transmission organization
12 intends to retire, it must submit documentation to the
13 appropriate regional transmission organization by the
14 appropriate deadline that meets all applicable regulatory
15 requirements necessary to obtain approval to permanently
16 cease operating the large GHG-emitting unit;

17 (2) if any EGU or large GHG-emitting unit that is a
18 participant in a regional transmission organization
19 receives notice that the regional transmission
20 organization has determined that continued operation of
21 the unit is required, the unit may continue operating
22 until the issue identified by the regional transmission
23 organization is resolved. The owner or operator of the
24 unit must cooperate with the regional transmission
25 organization in resolving the issue and must reduce its
26 emissions to zero, consistent with the requirements under

1 subsection (g), (h), (i), (j), (k), or (k-5), as
2 applicable, as soon as practicable when the issue
3 identified by the regional transmission organization is
4 resolved; and

5 (3) any large GHG-emitting unit that is not a
6 participant in a regional transmission organization shall
7 be allowed to continue emitting CO₂e and copollutants
8 after the zero-emission date specified in subsection (g),
9 (h), (i), (j), (k), or (k-5), as applicable, in the
10 capacity of an emergency backup unit if approved by the
11 Illinois Commerce Commission.

12 (m) No variance, adjusted standard, or other regulatory
13 relief otherwise available in this Act may be granted to the
14 emissions reduction and elimination obligations in this
15 Section.

16 (n) By June 30 of each year, beginning in 2025, the Agency
17 shall prepare and publish on its website a report setting
18 forth the actual greenhouse gas emissions from individual
19 units and the aggregate statewide emissions from all units for
20 the prior year.

21 (o) Every 5 years beginning in 2025, the Environmental
22 Protection Agency, Illinois Power Agency, and Illinois
23 Commerce Commission shall jointly prepare, and release
24 publicly, a report to the General Assembly that examines the
25 State's current progress toward its renewable energy resource
26 development goals, the status of CO₂e and copollutant

1 emissions reductions, the current status and progress toward
2 developing and implementing green hydrogen technologies, the
3 current and projected status of electric resource adequacy and
4 reliability throughout the State for the period beginning 5
5 years ahead, and proposed solutions for any findings. The
6 Environmental Protection Agency, Illinois Power Agency, and
7 Illinois Commerce Commission shall consult PJM
8 Interconnection, LLC and Midcontinent Independent System
9 Operator, Inc., or their respective successor organizations
10 regarding forecasted resource adequacy and reliability needs,
11 anticipated new generation interconnection, new transmission
12 development or upgrades, and any announced large GHG-emitting
13 unit closure dates and include this information in the report.
14 The report shall be released publicly by no later than
15 December 15 of the year it is prepared. If the Environmental
16 Protection Agency, Illinois Power Agency, and Illinois
17 Commerce Commission jointly conclude in the report that the
18 data from the regional grid operators, the pace of renewable
19 energy development, the pace of development of energy storage
20 and demand response utilization, transmission capacity, and
21 the CO₂e and copollutant emissions reductions required by
22 subsection (i) or (k-5) reasonably demonstrate that a resource
23 adequacy shortfall will occur, including whether there will be
24 sufficient in-state capacity to meet the zonal requirements of
25 MISO Zone 4 or the PJM ComEd Zone, per the requirements of the
26 regional transmission organizations, or that the regional

1 transmission operators determine that a reliability violation
2 will occur during the time frame the study is evaluating, then
3 the Illinois Power Agency, in conjunction with the
4 Environmental Protection Agency shall develop a plan to reduce
5 or delay CO₂e and copollutant emissions reductions
6 requirements only to the extent and for the duration necessary
7 to meet the resource adequacy and reliability needs of the
8 State, including allowing any plants whose emission reduction
9 deadline has been identified in the plan as creating a
10 reliability concern to continue operating, including operating
11 with reduced emissions or as emergency backup where
12 appropriate. The plan shall also consider the use of renewable
13 energy, energy storage, demand response, transmission
14 development, or other strategies to resolve the identified
15 resource adequacy shortfall or reliability violation.

16 (1) In developing the plan, the Environmental
17 Protection Agency and the Illinois Power Agency shall hold
18 at least one workshop open to, and accessible at a time and
19 place convenient to, the public and shall consider any
20 comments made by stakeholders or the public. Upon
21 development of the plan, copies of the plan shall be
22 posted and made publicly available on the Environmental
23 Protection Agency's, the Illinois Power Agency's, and the
24 Illinois Commerce Commission's websites. All interested
25 parties shall have 60 days following the date of posting
26 to provide comment to the Environmental Protection Agency

1 and the Illinois Power Agency on the plan. All comments
2 submitted to the Environmental Protection Agency and the
3 Illinois Power Agency shall be encouraged to be specific,
4 supported by data or other detailed analyses, and, if
5 objecting to all or a portion of the plan, accompanied by
6 specific alternative wording or proposals. All comments
7 shall be posted on the Environmental Protection Agency's,
8 the Illinois Power Agency's, and the Illinois Commerce
9 Commission's websites. Within 30 days following the end of
10 the 60-day review period, the Environmental Protection
11 Agency and the Illinois Power Agency shall revise the plan
12 as necessary based on the comments received and file its
13 revised plan with the Illinois Commerce Commission for
14 approval.

15 (2) Within 60 days after the filing of the revised
16 plan at the Illinois Commerce Commission, any person
17 objecting to the plan shall file an objection with the
18 Illinois Commerce Commission. Within 30 days after the
19 expiration of the comment period, the Illinois Commerce
20 Commission shall determine whether an evidentiary hearing
21 is necessary. The Illinois Commerce Commission shall also
22 host 3 public hearings within 90 days after the plan is
23 filed. Following the evidentiary and public hearings, the
24 Illinois Commerce Commission shall enter its order
25 approving or approving with modifications the reliability
26 mitigation plan within 180 days.

1 (3) The Illinois Commerce Commission shall only
2 approve the plan if the Illinois Commerce Commission
3 determines that it will resolve the resource adequacy or
4 reliability deficiency identified in the reliability
5 mitigation plan at the least amount of CO₂e and copollutant
6 emissions, taking into consideration the emissions impacts
7 on environmental justice communities, and that it will
8 ensure adequate, reliable, affordable, efficient, and
9 environmentally sustainable electric service at the lowest
10 total cost over time, taking into account the impact of
11 increases in emissions.

12 (4) If the resource adequacy or reliability deficiency
13 identified in the reliability mitigation plan is resolved
14 or reduced, the Environmental Protection Agency and the
15 Illinois Power Agency may file an amended plan adjusting
16 the reduction or delay in CO₂e and copollutant emission
17 reduction requirements identified in the plan.

18 (Source: P.A. 102-662, eff. 9-15-21; 102-1031, eff. 5-27-22.)

19 (Text of Section after amendment by P.A. 104-458)

20 Sec. 9.15. Greenhouse gases.

21 (a) An air pollution construction permit shall not be
22 required due to emissions of greenhouse gases if the
23 equipment, site, or source is not subject to regulation, as
24 defined by 40 CFR 52.21, as now or hereafter amended, for
25 greenhouse gases or is otherwise not addressed in this Section

1 or by the Board in regulations for greenhouse gases. These
2 exemptions do not relieve an owner or operator from the
3 obligation to comply with other applicable rules or
4 regulations.

5 (b) An air pollution operating permit shall not be
6 required due to emissions of greenhouse gases if the
7 equipment, site, or source is not subject to regulation, as
8 defined by Section 39.5 of this Act, for greenhouse gases or is
9 otherwise not addressed in this Section or by the Board in
10 regulations for greenhouse gases. These exemptions do not
11 relieve an owner or operator from the obligation to comply
12 with other applicable rules or regulations.

13 (c) (Blank).

14 (d) (Blank).

15 (e) (Blank).

16 (f) As used in this Section:

17 "Carbon dioxide emission" means the plant annual CO₂ total
18 output emission as measured by the United States Environmental
19 Protection Agency in its Emissions & Generation Resource
20 Integrated Database (eGrid), or its successor.

21 "Carbon dioxide equivalent emissions" or "CO₂e" means the
22 sum total of the mass amount of emissions in tons per year,
23 calculated by multiplying the mass amount of each of the 6
24 greenhouse gases specified in Section 3.207, in tons per year,
25 by its associated global warming potential as set forth in 40
26 CFR 98, subpart A, table A-1 or its successor, and then adding

1 them all together.

2 "Cogeneration" or "combined heat and power" refers to any
3 system that, either simultaneously or sequentially, produces
4 electricity and useful thermal energy from a single fuel
5 source.

6 "Copollutants" refers to the 6 criteria pollutants that
7 have been identified by the United States Environmental
8 Protection Agency pursuant to the Clean Air Act.

9 "Electric generating unit" or "EGU" means a fossil
10 fuel-fired stationary boiler, combustion turbine, or combined
11 cycle system that serves a generator that has a nameplate
12 capacity greater than 25 MWe and produces electricity for
13 sale.

14 "Environmental justice community" means the definition of
15 that term based on existing methodologies and findings, used
16 and as may be updated by the Illinois Power Agency and its
17 program administrator in the Illinois Solar for All Program.

18 "Equity investment eligible community" or "eligible
19 community" means the geographic areas throughout Illinois that
20 would most benefit from equitable investments by the State
21 designed to combat discrimination and foster sustainable
22 economic growth. Specifically, eligible community means the
23 following areas:

24 (1) areas where residents have been historically
25 excluded from economic opportunities, including
26 opportunities in the energy sector, as defined as R3 areas

1 pursuant to Section 10-40 of the Cannabis Regulation and
2 Tax Act; and

3 (2) areas where residents have been historically
4 subject to disproportionate burdens of pollution,
5 including pollution from the energy sector, as established
6 by environmental justice communities as defined by the
7 Illinois Power Agency pursuant to the Illinois Power
8 Agency Act, excluding any racial or ethnic indicators.

9 "Equity investment eligible person" or "eligible person"
10 means the persons who would most benefit from equitable
11 investments by the State designed to combat discrimination and
12 foster sustainable economic growth. Specifically, eligible
13 person means the following people:

14 (1) persons whose primary residence is in an equity
15 investment eligible community;

16 (2) persons whose primary residence is in a
17 municipality, or a county with a population under 100,000,
18 where the closure of an electric generating unit or mine
19 has been publicly announced or the electric generating
20 unit or mine is in the process of closing or closed within
21 the last 5 years;

22 (3) persons who are graduates of or currently enrolled
23 in the foster care system; or

24 (4) persons who were formerly incarcerated.

25 "Existing emissions" means:

26 (1) for CO₂e, the total average tons-per-year of CO₂e

1 emitted by the EGU or large GHG-emitting unit either in
2 the years 2018 through 2020 or, if the unit was not yet in
3 operation by January 1, 2018, in the first 3 full years of
4 that unit's operation; and

5 (2) for any copollutant, the total average
6 tons-per-year of that copollutant emitted by the EGU or
7 large GHG-emitting unit either in the years 2018 through
8 2020 or, if the unit was not yet in operation by January 1,
9 2018, in the first 3 full years of that unit's operation.

10 "Green hydrogen" means a power plant technology in which
11 an EGU creates electric power exclusively from electrolytic
12 hydrogen, in a manner that produces zero carbon and
13 copollutant emissions, using hydrogen fuel that is
14 electrolyzed using a 100% renewable zero carbon emission
15 energy source.

16 "Large greenhouse gas-emitting unit" or "large
17 GHG-emitting unit" means a unit that is an electric generating
18 unit or other fossil fuel-fired unit that itself has a
19 nameplate capacity or serves a generator that has a nameplate
20 capacity greater than 25 MWe and that produces electricity,
21 including, but not limited to, coal-fired, coal-derived,
22 oil-fired, natural gas-fired, and cogeneration units.

23 "NO_x emission rate" means the plant annual NO_x total output
24 emission rate as measured by the United States Environmental
25 Protection Agency in its Emissions & Generation Resource
26 Integrated Database (eGrid), or its successor, in the most

1 recent year for which data is available.

2 "Public greenhouse gas-emitting units" or "public
3 GHG-emitting unit" means large greenhouse gas-emitting units,
4 including EGUs, that are wholly owned, directly or indirectly,
5 by one or more municipalities, municipal corporations, joint
6 municipal electric power agencies, electric cooperatives, or
7 other governmental or nonprofit entities, whether organized
8 and created under the laws of Illinois or another state.

9 "SO₂ emission rate" means the "plant annual SO₂ total
10 output emission rate" as measured by the United States
11 Environmental Protection Agency in its Emissions & Generation
12 Resource Integrated Database (eGrid), or its successor, in the
13 most recent year for which data is available.

14 (g) All EGUs and large greenhouse gas-emitting units that
15 use coal or oil as a fuel and are not public GHG-emitting units
16 shall permanently reduce all CO₂e and copollutant emissions to
17 zero no later than January 1, 2030.

18 (h) All EGUs and large greenhouse gas-emitting units that
19 use coal as a fuel and are public GHG-emitting units shall
20 permanently reduce CO₂e emissions to zero no later than
21 December 31, 2045. Any source or plant with such units must
22 also reduce their CO₂e emissions by 45% from existing
23 emissions by no later than January 1, 2035. If the emissions
24 reduction requirement is not achieved by December 31, 2035,
25 the plant shall retire one or more units or otherwise reduce
26 its CO₂e emissions by 45% from existing emissions by June 30,

1 2038.

2 (i) All EGUs and large greenhouse gas-emitting units that
3 use gas as a fuel and are not public GHG-emitting units shall
4 permanently reduce all CO₂e and copollutant emissions to zero,
5 including through unit retirement or the use of 100% green
6 hydrogen or other similar technology that is commercially
7 proven to achieve zero carbon emissions, according to the
8 following:

9 (1) No later than January 1, 2030: all EGUs and large
10 greenhouse gas-emitting units that have a NO_x emissions
11 rate of greater than 0.12 lbs/MWh or a SO₂ emission rate of
12 greater than 0.006 lb/MWh, and are located in or within 3
13 miles of an environmental justice community designated as
14 of January 1, 2021 or an equity investment eligible
15 community.

16 (2) No later than January 1, 2040: all EGUs and large
17 greenhouse gas-emitting units that have a NO_x emission
18 rate of greater than 0.12 lbs/MWh or a SO₂ emission rate
19 greater than 0.006 lb/MWh, and are not located in or
20 within 3 miles of an environmental justice community
21 designated as of January 1, 2021 or an equity investment
22 eligible community. After January 1, 2035, each such EGU
23 and large greenhouse gas-emitting unit shall reduce its
24 CO₂e emissions by at least 50% from its existing emissions
25 for CO₂e, and shall be limited in operation to, on average,
26 6 hours or less per day, measured over a calendar year, and

1 shall not run for more than 24 consecutive hours except in
2 emergency conditions, as designated by a Regional
3 Transmission Organization or Independent System Operator.

4 (3) No later than January 1, 2035: all EGUs and large
5 greenhouse gas-emitting units that began operation prior
6 to the effective date of this amendatory Act of the 102nd
7 General Assembly and have a NO_x emission rate of less than
8 or equal to 0.12 lb/MWh and a SO₂ emission rate less than
9 or equal to 0.006 lb/MWh, and are located in or within 3
10 miles of an environmental justice community designated as
11 of January 1, 2021 or an equity investment eligible
12 community. Each such EGU and large greenhouse gas-emitting
13 unit shall reduce its CO₂e emissions by at least 50% from
14 its existing emissions for CO₂e no later than January 1,
15 2030.

16 (4) No later than January 1, 2040: All remaining EGUs
17 and large greenhouse gas-emitting units that have a heat
18 rate greater than or equal to 7000 BTU/kWh. Each such EGU
19 and Large greenhouse gas-emitting unit shall reduce its
20 CO₂e emissions by at least 50% from its existing emissions
21 for CO₂e no later than January 1, 2035.

22 (5) No later than January 1, 2045: all remaining EGUs
23 and large greenhouse gas-emitting units.

24 (j) All EGUs and large greenhouse gas-emitting units that
25 use gas as a fuel and are public GHG-emitting units shall
26 permanently reduce all CO₂e and copollutant emissions to zero,

1 including through unit retirement or the use of 100% green
2 hydrogen or other similar technology that is commercially
3 proven to achieve zero carbon emissions by January 1, 2045.

4 (k) All EGUs and large greenhouse gas-emitting units that
5 utilize combined heat and power or cogeneration technology
6 shall permanently reduce all CO₂e and copollutant emissions to
7 zero, including through unit retirement or the use of 100%
8 green hydrogen or other similar technology that is
9 commercially proven to achieve zero carbon emissions by
10 January 1, 2045.

11 (k-5) No EGU or large greenhouse gas-emitting unit that
12 uses gas as a fuel and is not a public GHG-emitting unit may
13 emit, in any 12-month period, CO₂e or copollutants in excess of
14 that unit's existing emissions for those pollutants.

15 (l) Notwithstanding subsections (g) through (k-5), large
16 GHG-emitting units including EGUs may temporarily continue
17 emitting CO₂e and copollutants after any applicable deadline
18 specified in any of subsections (g) through (k-5) if it has
19 been determined, as described in paragraphs (1) and (2) of
20 this subsection, that ongoing operation of the EGU is
21 necessary to maintain power grid supply and reliability or
22 ongoing operation of large GHG-emitting unit that is not an
23 EGU is necessary to serve as an emergency backup to
24 operations. Up to and including the occurrence of an emission
25 reduction deadline under subsection (i), all EGUs and large
26 GHG-emitting units must comply with the following terms:

1 (1) if an EGU or large GHG-emitting unit that is a
2 participant in a regional transmission organization
3 intends to retire, it must submit documentation to the
4 appropriate regional transmission organization by the
5 appropriate deadline that meets all applicable regulatory
6 requirements necessary to obtain approval to permanently
7 cease operating the large GHG-emitting unit;

8 (2) if any EGU or large GHG-emitting unit that is a
9 participant in a regional transmission organization
10 receives notice that the regional transmission
11 organization has determined that continued operation of
12 the unit is required, the unit may continue operating
13 until the issue identified by the regional transmission
14 organization is resolved. The owner or operator of the
15 unit must cooperate with the regional transmission
16 organization in resolving the issue and must reduce its
17 emissions to zero, consistent with the requirements under
18 subsection (g), (h), (i), (j), (k), or (k-5), as
19 applicable, as soon as practicable when the issue
20 identified by the regional transmission organization is
21 resolved; and

22 (3) any large GHG-emitting unit that is not a
23 participant in a regional transmission organization shall
24 be allowed to continue emitting CO₂e and copollutants
25 after the zero-emission date specified in subsection (g),
26 (h), (i), (j), (k), or (k-5), as applicable, in the

1 capacity of an emergency backup unit if approved by the
2 Illinois Commerce Commission.

3 (m) No variance, adjusted standard, or other regulatory
4 relief otherwise available in this Act may be granted to the
5 emissions reduction and elimination obligations in this
6 Section.

7 (n) By June 30 of each year, beginning in 2025, the Agency
8 shall prepare and publish on its website a report setting
9 forth the actual greenhouse gas emissions from individual
10 units and the aggregate statewide emissions from all units for
11 the prior year.

12 (o) The Environmental Protection Agency, Illinois Power
13 Agency, and Illinois Commerce Commission shall jointly
14 prepare, and release publicly, a report to the General
15 Assembly that examines the State's current progress toward its
16 renewable energy resource development goals, the status of
17 CO₂e and copollutant emissions reductions, the current status
18 and progress toward developing and implementing green hydrogen
19 technologies, the current and projected status of electric
20 resource adequacy and reliability throughout the State for the
21 period beginning 5 years ahead, and proposed solutions for any
22 findings. The Environmental Protection Agency, Illinois Power
23 Agency, and Illinois Commerce Commission shall consult PJM
24 Interconnection, LLC and Midcontinent Independent System
25 Operator, Inc., or their respective successor organizations
26 regarding forecasted resource adequacy and reliability needs,

1 anticipated new generation interconnection, new transmission
2 development or upgrades, and any announced large GHG-emitting
3 unit closure dates and include this information in the report.
4 The report shall be released publicly by no later than
5 December 15 of the year it is prepared. If the Environmental
6 Protection Agency, Illinois Power Agency, and Illinois
7 Commerce Commission jointly conclude in the report that the
8 data from the regional grid operators, the pace of renewable
9 energy development, the pace of development of energy storage
10 and demand response utilization, transmission capacity, and
11 the CO₂e and copollutant emissions reductions required by
12 subsection (i) or (k-5) reasonably demonstrate that a resource
13 adequacy shortfall will occur, including whether there will be
14 sufficient in-state capacity to meet the zonal requirements of
15 MISO Zone 4 or the PJM ComEd Zone, per the requirements of the
16 regional transmission organizations, or that the regional
17 transmission operators determine that a reliability violation
18 will occur during the time frame the study is evaluating, then
19 the Illinois Power Agency, in conjunction with the
20 Environmental Protection Agency and in conjunction with the
21 integrated resource plan under Sections 16-201 and 16-202 of
22 the Public Utilities Act, shall develop a plan to reduce or
23 delay CO₂e and copollutant emissions reductions requirements
24 only to the extent and for the duration necessary to meet the
25 resource adequacy and reliability needs of the State,
26 including allowing any plants whose emission reduction

1 deadline has been identified in the plan as creating a
2 reliability concern to continue operating, including operating
3 with reduced emissions or as emergency backup where
4 appropriate. The plan shall also consider the use of renewable
5 energy, energy storage, demand response, transmission
6 development, or other strategies to resolve the identified
7 resource adequacy shortfall or reliability violation.

8 ~~(1)~~ In developing the plan, the Environmental Protection
9 Agency and the Illinois Power Agency shall hold at least one
10 workshop open to, and accessible at a time and place
11 convenient to, the public and shall consider any comments made
12 by stakeholders or the public. Upon development of the plan,
13 copies of the plan shall be posted and made publicly available
14 on the Environmental Protection Agency's, the Illinois Power
15 Agency's, and the Illinois Commerce Commission's websites. The
16 ~~All interested parties shall have 60 days following the date~~
17 ~~of posting to provide comment to the Environmental Protection~~
18 ~~Agency and the Illinois Power Agency on the plan. All comments~~
19 ~~submitted to the Environmental Protection Agency and the~~
20 ~~Illinois Power Agency shall be encouraged to be specific,~~
21 ~~supported by data or other detailed analyses, and, if~~
22 ~~objecting to all or a portion of the plan, accompanied by~~
23 ~~specific alternative wording or proposals. All comments shall~~
24 ~~be posted on the Environmental Protection Agency's, the~~
25 ~~Illinois Power Agency's, and the Illinois Commerce~~
26 ~~Commission's websites. Within 30 days following the end of the~~

1 ~~60-day review period, the~~ Environmental Protection Agency and
2 the Illinois Power Agency shall ~~revise the plan as necessary~~
3 ~~based on the comments received and file~~ the ~~its revised plan~~
4 with the Illinois Commerce Commission for review in
5 conjunction with the integrated resource plan under Sections
6 16-201 and 16-202 of the Public Utilities Act approval.

7 ~~(2) Within 60 days after the filing of the revised~~
8 ~~plan at the Illinois Commerce Commission, any person~~
9 ~~objecting to the plan shall file an objection with the~~
10 ~~Illinois Commerce Commission. Within 30 days after the~~
11 ~~expiration of the comment period, the Illinois Commerce~~
12 ~~Commission shall determine whether an evidentiary hearing~~
13 ~~is necessary. The Illinois Commerce Commission shall also~~
14 ~~host 3 public hearings within 90 days after the plan is~~
15 ~~filed. Following the evidentiary and public hearings, the~~
16 ~~Illinois Commerce Commission shall enter its order~~
17 ~~approving or approving with modifications the reliability~~
18 ~~mitigation plan within 180 days.~~

19 ~~(3) The Illinois Commerce Commission shall only~~
20 ~~approve the plan if the Illinois Commerce Commission~~
21 ~~determines that it will resolve the resource adequacy or~~
22 ~~reliability deficiency identified in the reliability~~
23 ~~mitigation plan at the least amount of CO₂e and copollutant~~
24 ~~emissions, taking into consideration the emissions impacts~~
25 ~~on environmental justice communities, and that it will~~
26 ~~ensure adequate, reliable, affordable, efficient, and~~

1 ~~environmentally sustainable electric service at the lowest~~
2 ~~total cost over time, taking into account the impact of~~
3 ~~increases in emissions.~~

4 ~~(4) If the resource adequacy or reliability deficiency~~
5 ~~identified in the reliability mitigation plan is resolved~~
6 ~~or reduced, the Environmental Protection Agency and the~~
7 ~~Illinois Power Agency may file an amended plan adjusting~~
8 ~~the reduction or delay in CO₂e and copollutant emission~~
9 ~~reduction requirements identified in the plan.~~

10 (Source: P.A. 104-458, eff. 6-1-26.)

11 Section 95. No acceleration or delay. Where this Act makes
12 changes in a statute that is represented in this Act by text
13 that is not yet or no longer in effect (for example, a Section
14 represented by multiple versions), the use of that text does
15 not accelerate or delay the taking effect of (i) the changes
16 made by this Act or (ii) provisions derived from any other
17 Public Act.

18 Section 99. Effective date. This Act takes effect upon
19 becoming law.

1 INDEX

2 Statutes amended in order of appearance

3 New Act

4 220 ILCS 5/16-107.6

5 220 ILCS 5/16-107.9

6 220 ILCS 33/5-10

7 415 ILCS 5/9.15