Company Exhibit No. __
Witness: NJF
Schedule 2
Page 1 of 2

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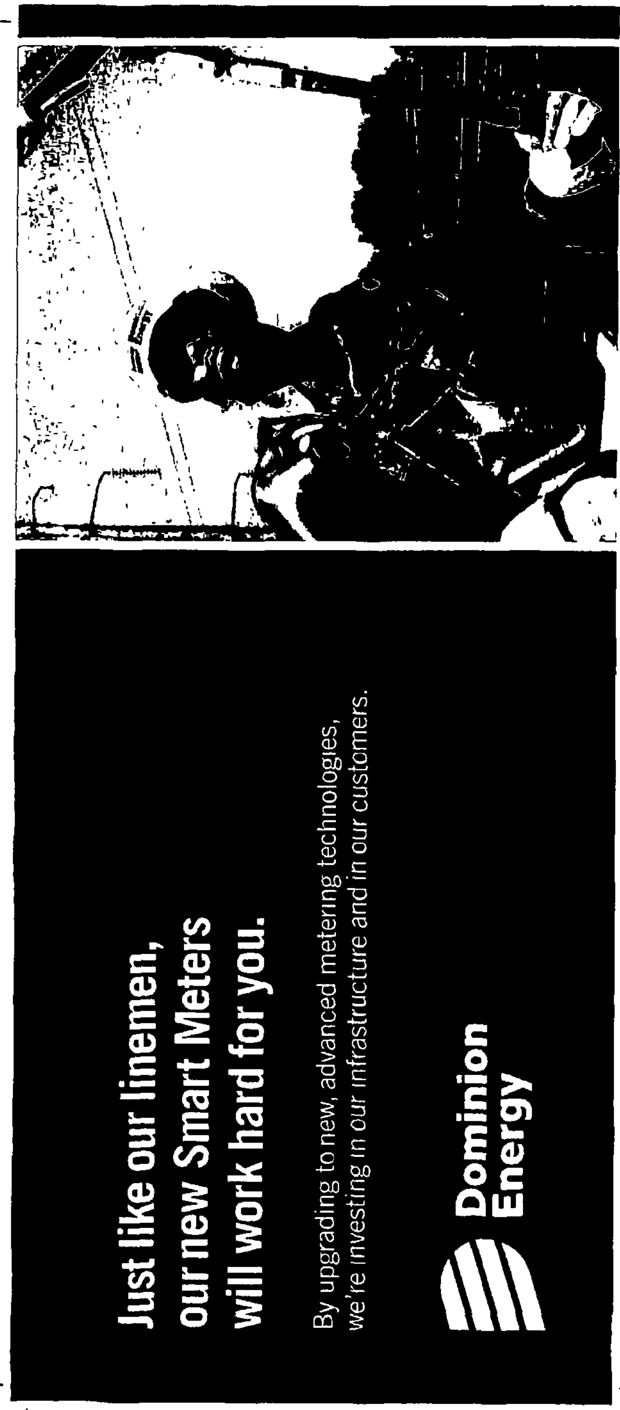

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12/7/18 9:26 AM

Smart Meters: our newest metering technology for managing energy.

You're due for an upgrade. Soon, Dominion will be exchanging existing meters in your area for new Smart Meters. Why? To continue providing you with better service–like more reliable delivery of energy, better power-outage detection, faster problem resolution and remote meter reading. Smart meters also allow you to view your daily energy usage and participate in pricing plans which help you manage energy and costs.

The meter upgrade will require only a momentary power interruption; no need for you to make an appointment or be present during the exchange.

For more information, including how to view your daily energy usage, please visit DominionEnergy.com/smartmeter

The meter upgrade will occur at:

Dominion Energy®

P.O. Box 26666
Richmond, VA 23261

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Page 2 of 2

Company Exhibit No. ___
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Schedule 3
Page 1 of 2

Dominion Energy

DOES NOT
PRINT-DIE
INDICATOR

By upgrading to new, advanced metering technologies, we're investing in our infrastructure and in our customers.

Date ______________________

☐ **A utility service representative upgraded the electric meter today.** If you have any questions or concerns related to the meter exchange, please call:

866-566-6436 | 8 AM to 5 PM, Monday to Friday

☐ A utility service representative stopped by today to upgrade the electric meter. However, **the meter could not be exchanged due to:**

____

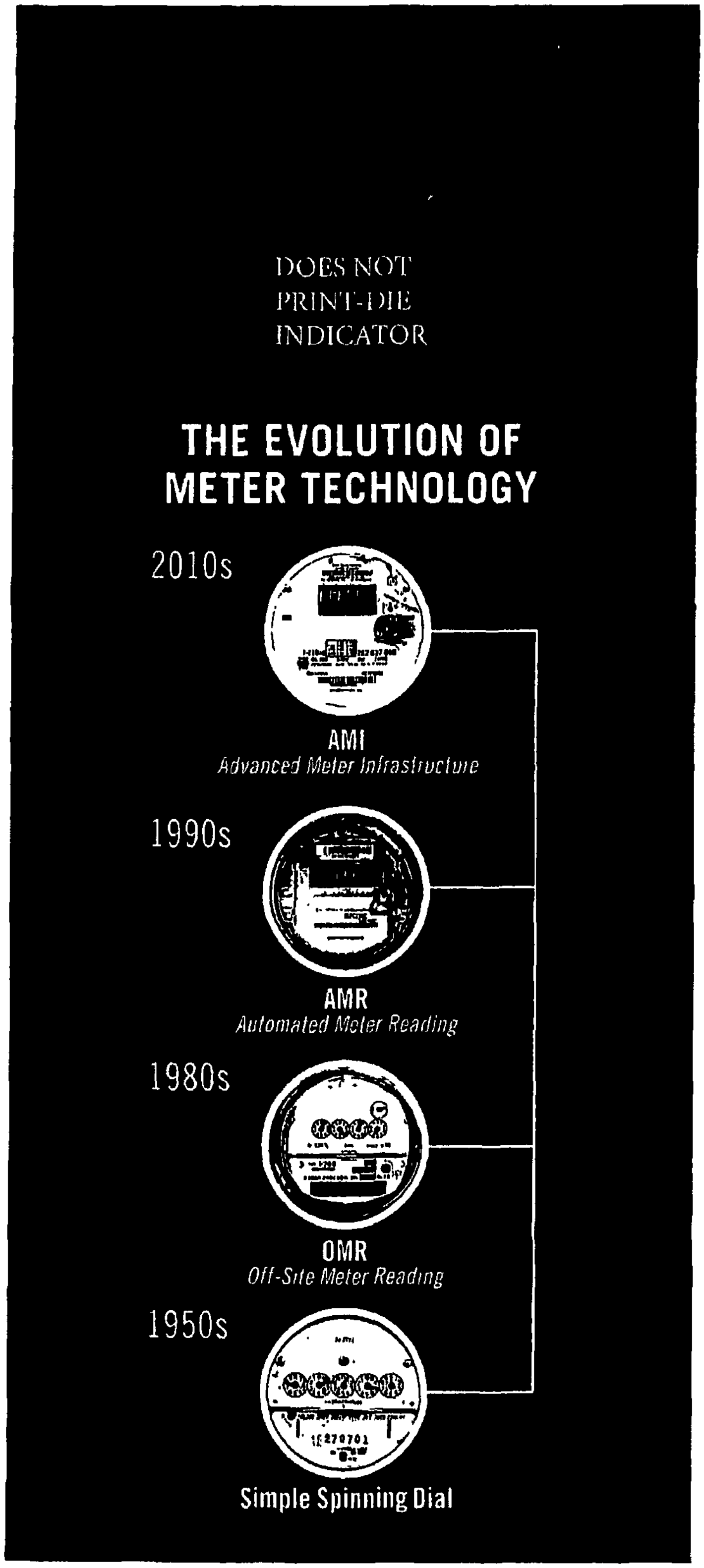
____

To discuss the issue and reschedule the meter upgrade, please call:

844-562-9472 | 8 AM to 5 PM, Monday to Friday

DominionEnergy.com/smartmeter

Company Exhibit No. __
Witness: NJF
Schedule 3
Page 2 of 2



Company Exhibit No. __
Witness: NJF
Schedule 4
Page 1 of 5

<Premise Address>

<Account Number>

<Mailing Address>

<Date>

Dear Valued Customer,

Dominion Energy is committed to providing safe and reliable energy to our customers by investing in our infrastructure. As part of this commitment, we are currently upgrading to smart meters in your area.

This letter is in response to your inquiry for more information about the **Interim Non-Communicating Meter Option (Residential "Opt-Out")**. If you decide to opt-out, the meter at your location will be replaced with non-communicating equipment. The non-communicating meter does not have any data storage features or two way communication functions enabled. As a result, it will be necessary for a meter reader to obtain a visual meter reading monthly.

Smart meters allow innovative features to:

- give you more control over how you use energy by providing you with information about energy usage;
- notify Dominion Energy when your power is out and back on for efficient restoration; and
- offer flexible, alternative pricing structures based on usage data.

Please find a summary comparing smart meters (communicating) to the opt-out program meters (non-communicating).

<u>Comparison of Meter Features</u>

	Standard Smart Meters (Communicating)	Opt-Out Program Meters (Non-Communicating)
Remote Outage Detection	**Yes**	**No**
Remote Service Connection	**Yes**	**No**
Customer Pricing Plan Options	**Yes**	**No**

Currently, Dominion Energy does not charge any special installation or usage fees to customers who choose the Interim Non-Communicating Meter Option; however, since manual monthly meter readings are required for these non-communicating meters, Dominion Energy may propose recovering expenses in the future. Such fees are subject to approval by the State Corporation Commission of Virginia (SCC) and, if approved, Dominion Energy will inform all participants of the Interim Non-Communicating Meter Option.

Hopefully, you will agree upgrading to a smart meter offers many benefits and is the best option for you. Should you wish to opt-out, please review the enclosed Interim Non-Communicating Meter Option requirements and **<u>sign and return the Enrollment Form</u>** as soon as possible.

A meter exchange will be necessary regardless of which meter you choose. Service will be momentarily interrupted during the meter exchange. Customers do not need to be present for the meter exchange, provided adequate access to the meter is available. Please visit our website at DominionEnergy.com/smartmeter or call 1-866-566-6436 for additional information.

Sincerely,

Smart Meter Team
Dominion Energy

Enclosures:
Interim Non-Communicating Meter Option Requirements
Enrollment Form

By receiving electric service from Dominion Energy, customers are subject to the Company's Terms and Conditions for the Provision of Electric Services. Pursuant to Section V of the Terms and Conditions, Dominion Energy owns the meter currently installed at your residence/business and has the right to have unobstructed, safe, and convenient access including but not limited to repair, replace, or exchange the meter. Additionally, as stated in Section XV, Dominion Energy has the right to access customer premises at all reasonable times for the purpose of reading meters, removing its property, and for other proper purposes such as the meter exchange. For an electronic version of Dominion Energy's Terms and Conditions please visit our website, DominionEnergy.com/terms.

Interim Non-Communicating Meter Option
REQUIREMENTS

The following requirements apply to the Interim Non-Communicating Meter (Residential Opt-Out) Option. The Non-Communicating meters are Advanced Metering Infrastructure ("AMI") or Smart Meters with both the two-way communications and data storage features disabled; the only recording features retained are the minimum needed for monthly billing. Because the Non-Communicating Meters' remote communication abilities have been disabled, a Dominion Energy ("Company") representative will manually read the meter.

To participate in this Option, please review these requirements and then sign and return the enclosed enrollment form.

Eligibility Requirements Guidelines and Restrictions

- These Option specific requirements are in addition to the Company's *Terms and Conditions for the Provision of Electric Service* ("Terms and Conditions") currently on file with the State Corporation Commission of Virginia ("Commission"), under which customers receive their Electric Service.
- An Interim Non-Communicating Meter Option Participant (the "Participant") must be a residential customer and can only request the Interim Non-Communicating Meter Option for accounts which they have authority to make account level changes. The Participant must submit an individual enrollment form for each account which enrollment is requested.
- The Participant must already have an AMI meter, or currently scheduled for an AMI meter upgrade.
- Participant must currently receive Electric Service from the Company in accordance with residential Rate Schedule 1 or transfer to Rate Schedule 1 prior to enrolling in the Interim Non-Communicating Meter Option. Non-Communicating Meters are not applicable for customers receiving Electric Service on dynamic-pricing (e.g., Rate Schedule DP-R) or any residential time-of-use rate schedule (e.g., Rate Schedule 1P, 1S, or 1T). In addition, Non-Communicating Meters are not applicable to situations in which the customer generates electricity or additional metering data is required for billing (e.g., Net Metering and Bidirectional Metering, Rate Schedule SP – Solar Purchase (Experimental)).
- The Participant is responsible for providing and maintaining access to the Company for purposes of meter installation, maintenance, and reading, in accordance with Section XV of the Company's Terms and Conditions. The Company has the right of access to the Participant's premises at all reasonable times and must have safe access to the meter.

The Company reserves the right to discontinue this Interim Non-Communicating Meter Option, if such access is not provided and maintained by the Participant.

- The Company has the right to modify these requirements from time to time at its discretion. The most recent version of the requirements is available on the Company's website at DominionEnergy.com/smartmeter.

- The Company plans to propose a charge for the Non-Communicating Meter Option, which will be subject to approval by the Commission. Upon Commission approval, the Company will inform customers who are currently participating in the Interim Non-Communicating Meter Option and will require such customers to enroll in the Commission approved Non-Communicating Meter Option, subject to any Commission approved fee, in order to continue using a Non-Communicating Meter. At that time, the Company will begin assessing any Commission approved fee for customers participating in the Non-Communicating Meter Option.

- Smart Meters help the Company operate its electric distribution infrastructure more efficiently by reducing the amount of excess voltage generated. As a result, customers and the Company may experience savings. By participating in the Non-Communicating Meter Option, the Participant acknowledges that the Company's ability to identify voltage-related concerns, notwithstanding the requirements set forth in Section VII of its Terms and Conditions, may be delayed or compromised.

- Upon receipt and approval of the completed enrollment form, the Company will schedule a meter exchange to coincide with the AMI deployment schedule. In cases where an AMI meter is already installed, the exchange to the Non-Communicating Meter will be completed within three weeks. Service will be momentarily interrupted during the meter exchange process. Customers do not have to be home for the meter exchange as long as adequate access to the existing meter is available.

- Accounts must be in good standing without any pending, recently completed, or active credit activity scheduled on the account.

- Participants may contact the Company to withdraw from the Interim Non-Communicating Meter Option at 1-866-566-6436 between 8:00 a.m. and 5:00 p.m. (Eastern Time) Monday through Friday.

Interim Non-Communicating Meter Option
ENROLLMENT FORM

Customers electing to enroll in the Interim Non-Communicating Meter (Residential Opt-Out) Option are required to complete this enrollment form and return it in the enclosed envelope or by email to ReceivedOpt-OutEnrollmentForms@DominionEnergy.com. Once Dominion Energy has received this signed and completed form, the enrollment will be processed and scheduled in accordance with the Interim Non-Communication Meter Requirements.

Customer Name and Address:

<XXXXX>
<XXXXX>
<XXXXX>

Account Number:

<XXXXXXXXXX>

By signing below, I hereby certify that I have the authority to make account level changes on the account listed above, and that I have fully read and agree to be bound by the requirements of the Interim Non-Communicating Meter Option. The latest requirements can be found at DominionEnergy.com/smartmeter.

PRINTED NAME:

____

SIGNATURE: DATE:

______________________________ ______________

Company Exhibit No. __
Witness: NJF
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Smart Meter Opt-Out Policy (DRAFT)

Dominion Energy is committed to providing safe and reliable energy to our customers by investing in our infrastructure. As part of this commitment, we are currently upgrading to smart meters.

Smart meters enable innovative features to:

- provide the customer with detailed information about their energy usage;
- offer flexible, alternative pricing structures based on detailed energy usage data; and
- notify the Company when a customer's power is out and back on, improving restoration efficiency.

Clearly upgrading to a smart meter offers many benefits and is the best option for the vast majority of customers. However, for customers who prefer not to have a smart meter, Dominion Energy does offer an opt-out program, with some limitations.

Opt-out limitations:

- Customers must take electric service from Dominion Energy under residential rate Schedule 1. Customers receiving electric service on any time-of-use or demand rate and customers who generate electricity are ineligible due to additional data required for billing and/or operating purposes.
- Accounts must be in good standing without any pending or recently completed (within the last 12 months) adverse credit activity with Dominion Energy.
- As per the Company's *Terms and Conditions for the Provision of Electric Service* as approved by the State Corporation Commission of Virginia, meters must be readily accessible to the Company, as walk-up meter reading will be required on a monthly basis.
- Customers must sign and return the Smart Meter Opt-Out Program enrollment form.
- Customers must allow the Company to exchange the current meter for a non-communicating digital meter. Legacy meters will be exchanged for non-communicating digital meters, as legacy meter reading and meter data processing systems are being retired.

Fees for Smart Meter Opt-Out Program

Due to the fact that additional efforts must be expended to administer the opt-out program, create an opt-out version of the meter, and read the non-communicating meter via walk-up procedures in perpetuity, the following fees will apply to customers who choose to opt out of smart meter implementation based on 2019 cost data:

- One-time initial fee: $84.53
- Ongoing monthly fee: $29.20

Opt-Out fees are subject to SCC approval and subject to revision.

Opt-Out Enrollment, Meter Exchange and On-going Meter Reading Cost Projections

Initial exchange/installation of non-communicating meter

Tasks	Time Spent per opt-out customer	Hourly Rate	Total	Note
Program administration and reporting, customer communications, work order generation/scheduling	0.75	$45.75	$34.31	(1)
Meter order processing, inventory management, shipping	0.5	$42.78	$21.39	(2)
Meter exchange	0.5	$58.55	$29.27	(3)
Credit based upon current costs being recovered in rates			($0.45)	
Total			$84.53	

Notes:

(1) Average/combination of Metering Solutions Ops Analyst and Lead Field Metering Analyst; pay grade mid-point, loaded rate
(2) Loaded Hourly Rate of a Shop Meterman
(3) Loaded hourly Meter Servicer + Vehicle rate; Time spent is calculated based on average numer of service order completions in a day in 2019

Monthly Fee

Department	Time Spent	Hourly Rate	Total	Note
Meter read	0.5	$58.55	$29.27	(4)
Credit based upon current costs being recovered in rates			($0.07)	
Total			$29.20	

(4) Loaded hourly Meter Servicer + Vehicle rate; Time spent is calculated based on projected average numer of service order completions in a day post-AMI deployment

Company Exhibit No.__
Witness: NJF
Schedule 6
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TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES

A. When meters are installed by the Company to measure the Electric Service used by the Company's Customers, all charges for Electric Service used, except certain minimum charges, shall be calculated from the readings of such meters. All meters used to determine billing will be owned and operated by the Company. The Company may for its own purposes use meters that are read remotely.

B. Normally, Electric Service will be furnished and metered through one Delivery Point and will be billed separately on the applicable Rate Schedule selected by the Customer. However, the Company reserves the right where for the Company's own purposes because of the amount or characteristics of electricity required, to install two or more sets of metering apparatus, to combine the readings of meters so installed for billing purposes, and to bill these combined readings on the applicable Rate Schedule selected by the Customer.

C. When one or more transformers are installed at one Delivery Point by the Company for the Company's convenience to provide Electric Service to a single Customer at one nominal voltage, the Company reserves the right, where for the Company's own purposes because of the amount or characteristics of electricity required, to meter the electricity on the Company's side of the transformer or transformers, but the Customer will then be allowed a discount of 2% in the Company's charges that are priced per kilowatt-hour.

D. Meters in service may be tested by the Company, the Commission or any other lawfully constituted authority having jurisdiction. When, as a result of such a test, a meter is found to be no more than 2% fast or slow, no adjustment will be made in the Customer's bills. If the meter is found to be more than 2% fast or slow because of incorrect calibration, the Company will rebill the Customer for the correct amount as calculated for a period equal to the lesser of:

1. One-half of the time elapsed since the most recent test of the metering apparatus.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

The percentage registration of a meter will be calculated by the "weighted average" of light load and full load, which is calculated by giving a value of 1 to the light load and a value of 4 to the full load.

E. Whenever it is found that unmetered Electric Service is being used as a result of tampering, the Customer will pay to the Company an amount estimated by the Company to be sufficient to cover the Electric Service used but not recorded by the meter and for which the Customer has not previously paid.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

F. Whenever it is found that, for reasons other than incorrect calibration or tampering, the Company has not properly billed the Customer, the Company will rebill the Customer in accordance with the terms of this paragraph. In the event the true amount of Electric Service used by the Customer cannot be determined, an estimate will be made of the Electric Service used during the period in question. Such estimate will be based on all known pertinent facts and will be used in calculating the corrected bill. The period of rebilling under this paragraph will be the lesser of the following:

Undercharges

1. The period during which improper billing occurred. .

2. 150 days for Customers having a maximum demand below 50 kW during the past year.

3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

Overcharges

The period of rebilling for overcharges under this paragraph will be for the period during which the improper billing occurred not to exceed 36 months, unless the Customer can provide original bills beyond the 36-month period to support any additional refund amount.

G. If, during the term of agreement for furnishing Electric Service to a Customer, the Customer is unable to operate the Customer's facilities, in whole or in part, because of accident, act of God, fire, or strike of the Customer's employees occurring at the location where Electric Service is supplied, the charge for Electric Service used during the period reasonably necessary to correct any such conditions will be reasonably adjusted in accordance with all pertinent facts and conditions.

H. As provided for in the tables below, Interval Meters and Contact Closures shall be available to all of the Company's Customers upon Customer request and in accordance with Rule 20 VAC 5-312-120 of the Commission's "Rules Governing Retail Access to Competitive Energy Services."

The specified charges for each option shall apply as follows:

1. The applicable Installation Charge listed below shall be increased by the Tax Effect Recovery Factor, pursuant to Rider D - Tax Effect Recovery, and shall be paid by the Customer prior to the installation.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

2. In addition, the Customer shall pay an on-going Monthly O & M Charge that is equal to the applicable Installation Charge multiplied by the charge found in Section IV.E.4. (b) of the Terms and Conditions. Such payment will continue until the Interval Metering Service Option is discontinued in accordance with item 3., below.

3. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Interval Metering Service Option, b) the Customer discontinues Electric Service at the location of the Interval Metering Service Option, or c) the Customer elects to receive metering service from a competitive meter provider, when such service is available.

4. Company will acknowledge receipt of Customer's request for Interval Metering Service Options in writing within five business days after receiving such request. Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once Customer has completed the applicable prerequisites, Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charges and One-time Removal Charges for the Interval Metering Service Options are as follows:

Interval Metering Service Options Installation and Removal Charges for Interval Meters		
Type	**Installation Charge**	**Removal Charge**
Single-phase, 240 Volt, class 200	$271.50	$62.38
Single-phase, 240 Volt, 3 wire, class 320	$216.48	$62.38
Single-phase, 240 Volt, 3 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 200 and 320, or class 10 and 20	$233.79	$143.75

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

Installation and Removal Charges for Contact Closures (for kW Data Only)		
Type	**Installation Charge**	**Removal Charge**
One Circuit (Assumes Recorder Under Glass), or Single Service (Assumes Demand Meter Installation)	$203.77	$108.49
Additional Circuits at Same Site (Assumes Recorder Under Glass)	$122.40	$27.12

If Customer requests a special metering functionality (i.e., an Interval Metering Service Option configuration that is different from the types stated above, and that is determined by the Company to be within its capability to provide), the Company will acknowledge receipt of Customer's request for the special metering functionality in writing within five business days after receiving such request. The Company's response shall indicate that within 30 days the Company will provide the Customer with the applicable Installation Charge (calculated by the Company on the basis of net incremental cost), Removal Charge, Monthly O & M Charge, the process, and the Customer's prerequisites, which must be completed before the Company can commence and complete the installation of the special metering functionality. Once Customer has completed the applicable prerequisites, Company shall provide the special metering functionality within 45 calendar days, or as promptly as working conditions permit.

The Company will own interval metering service devices used for measuring and billing the Customer for its consumption of demand and energy. The Company is responsible for the installation and removal of all meters.

I. Former Schedule SG Customers, who elect to keep the standby generator meter while purchasing Electricity Supply Service from a Competitive Service Provider, shall continue to pay the Company the $89.69 monthly charge, as described in Schedule SG, Paragraph II.A., and any related facilities charges, if applicable.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

J. As provided for in the table below, Non-communicating Meters shall be available to Customers served under Residential Service – Schedule 1 upon Customer request. If a Customer chooses to opt-out of the smart meter installation, the Customer may request to have a Non-communicating Meter installed.

The specified charges for this option shall apply as follows:

1. The Customer shall pay an on-going Monthly Charge to read the Customer's Non-communicating Meter. Such payment shall continue until the Non-communicating Metering Service Option is discontinued in accordance with item 2, below.
2. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Non-communicating Metering Service Option, or b) the Customer discontinues Electric Service at the location of the Non-communicating Metering Service Option.
3. The Company will acknowledge receipt of Customer's request for the Non-communicating Metering Service Option in writing within five business days after receiving such request. The Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once the Customer has completed the applicable prerequisites, the Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charge, One-time Removal Charge, and On-going Monthly Charge for the Non-communicating Metering Service Option are as follows:

Non-communicating Metering Service Option(s) Installation, Removal, and On-going Charges for Non-communicating Meters			
Type	**Installation Charge**	**Removal Charge**	**On-going Monthly Charge**
Single-phase, 240 Volt, class 200	$84.53	$29.20	$29.20

The Company will own Non-communicating Meters used for measuring and billing the Customer for its consumption of energy. The Company is responsible for the installation and removal of all meters.

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES

A. When meters are installed by the Company to measure the Electric Service used by the Company's Customers, all charges for Electric Service used, except certain minimum charges, shall be calculated from the readings of such meters. All meters used to determine billing will be owned and operated by the Company. The Company may for its own purposes use meters that are read remotely.

B. Normally, Electric Service will be furnished and metered through one Delivery Point and will be billed separately on the applicable Rate Schedule selected by the Customer. However, the Company reserves the right where for the Company's own purposes because of the amount or characteristics of electricity required, to install two or more sets of metering apparatus, to combine the readings of meters so installed for billing purposes, and to bill these combined readings on the applicable Rate Schedule selected by the Customer.

C. When one or more transformers are installed at one Delivery Point by the Company for the Company's convenience to provide Electric Service to a single Customer at one nominal voltage, the Company reserves the right, where for the Company's own purposes because of the amount or characteristics of electricity required, to meter the electricity on the Company's side of the transformer or transformers, but the Customer will then be allowed a discount of 2% in the Company's charges that are priced per kilowatt-hour.

D. Meters in service may be tested by the Company, the Commission or any other lawfully constituted authority having jurisdiction. When, as a result of such a test, a meter is found to be no more than 2% fast or slow, no adjustment will be made in the Customer's bills. If the meter is found to be more than 2% fast or slow because of incorrect calibration, the Company will rebill the Customer for the correct amount as calculated for a period equal to the lesser of:

1. One-half of the time elapsed since the most recent test of the metering apparatus.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

The percentage registration of a meter will be calculated by the "weighted average" of light load and full load, which is calculated by giving a value of 1 to the light load and a value of 4 to the full load.

E. Whenever it is found that unmetered Electric Service is being used as a result of tampering, the Customer will pay to the Company an amount estimated by the Company to be sufficient to cover the Electric Service used but not recorded by the meter and for which the Customer has not previously paid.

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

F. Whenever it is found that, for reasons other than incorrect calibration or tampering, the Company has not properly billed the Customer, the Company will rebill the Customer in accordance with the terms of this paragraph. In the event the true amount of Electric Service used by the Customer cannot be determined, an estimate will be made of the Electric Service used during the period in question. Such estimate will be based on all known pertinent facts and will be used in calculating the corrected bill. The period of rebilling under this paragraph will be the lesser of the following:

Undercharges

1. The period during which improper billing occurred.
2. 150 days for Customers having a maximum demand below 50 kW during the past year.
3. 12 months for Customers having a maximum demand of 50 kW or more during the past year.

Overcharges

The period of rebilling for overcharges under this paragraph will be for the period during which the improper billing occurred not to exceed 36 months, unless the Customer can provide original bills beyond the 36-month period to support any additional refund amount.

G. If, during the term of agreement for furnishing Electric Service to a Customer, the Customer is unable to operate the Customer's facilities, in whole or in part, because of accident, act of God, fire, or strike of the Customer's employees occurring at the location where Electric Service is supplied, the charge for Electric Service used during the period reasonably necessary to correct any such conditions will be reasonably adjusted in accordance with all pertinent facts and conditions.

H. As provided for in the tables below, Interval Meters and Contact Closures shall be available to all of the Company's Customers upon Customer request and in accordance with Rule 20 VAC 5-312-120 of the Commission's "Rules Governing Retail Access to Competitive Energy Services."

The specified charges for each option shall apply as follows:

1. The applicable Installation Charge listed below shall be increased by the Tax Effect Recovery Factor, pursuant to Rider D - Tax Effect Recovery, and shall be paid by the Customer prior to the installation.

(Continued)

Virginia Electric and Power Company

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

2. In addition, the Customer shall pay an on-going Monthly O & M Charge that is equal to the applicable Installation Charge multiplied by the charge found in Section IV.E.4. (b) of the Terms and Conditions. Such payment will continue until the Interval Metering Service Option is discontinued in accordance with item 3., below.

3. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Interval Metering Service Option, b) the Customer discontinues Electric Service at the location of the Interval Metering Service Option, or c) the Customer elects to receive metering service from a competitive meter provider, when such service is available.

4. Company will acknowledge receipt of Customer's request for Interval Metering Service Options in writing within five business days after receiving such request. Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once Customer has completed the applicable prerequisites, Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charges and One-time Removal Charges for the Interval Metering Service Options are as follows:

Interval Metering Service Options Installation and Removal Charges for Interval Meters		
Type	**Installation Charge**	**Removal Charge**
Single-phase, 240 Volt, class 200	$271.50	$62.38
Single-phase, 240 Volt, 3 wire, class 320	$216.48	$62.38
Single-phase, 240 Volt, 3 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 400	$787.70	$143.75
Three-phase, 120 Volt, 4 wire, class 200 and 320, or class 10 and 20	$233.79	$143.75

(Continued)

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

Installation and Removal Charges for Contact Closures (for kW Data Only)		
Type	**Installation Charge**	**Removal Charge**
One Circuit (Assumes Recorder Under Glass), or Single Service (Assumes Demand Meter Installation)	$203.77	$108.49
Additional Circuits at Same Site (Assumes Recorder Under Glass)	$122.40	$27.12

If Customer requests a special metering functionality (i.e., an Interval Metering Service Option configuration that is different from the types stated above, and that is determined by the Company to be within its capability to provide), the Company will acknowledge receipt of Customer's request for the special metering functionality in writing within five business days after receiving such request. The Company's response shall indicate that within 30 days the Company will provide the Customer with the applicable Installation Charge (calculated by the Company on the basis of net incremental cost), Removal Charge, Monthly O & M Charge, the process, and the Customer's prerequisites, which must be completed before the Company can commence and complete the installation of the special metering functionality. Once Customer has completed the applicable prerequisites, Company shall provide the special metering functionality within 45 calendar days, or as promptly as working conditions permit.

The Company will own interval metering service devices used for measuring and billing the Customer for its consumption of demand and energy. The Company is responsible for the installation and removal of all meters.

I. Former Schedule SG Customers, who elect to keep the standby generator meter while purchasing Electricity Supply Service from a Competitive Service Provider, shall continue to pay the Company the $89.69 monthly charge, as described in Schedule SG, Paragraph II.A., and any related facilities charges, if applicable.

TERMS AND CONDITIONS

X. BILLING AND RE-BILLING OF METERED AND UNMETERED SERVICES (Continued)

J. As provided for in the table below, Non-communicating Meters shall be available to Customers served under Residential Service – Schedule 1 upon Customer request. If Customer chooses to opt-out of the smart meter installation, the Customer may request to have a Non-communicating Meter installed.

The specified charges for this option shall apply as follows:

1. The Customer shall pay an on-going Monthly Charge to read the Customer's Non-communicating Meter. Such payment shall continue until the Non-communicating Metering Service Option is discontinued in accordance with item 2, below.

2. The One-time Removal Charge shall apply when either a) the Customer requests removal of the Non-communicating Metering Service Option, or b) the Customer discontinues Electric Service at the location of the Non-communicating Metering Service Option.

3. The Company will acknowledge receipt of Customer's request for Non-communicating Metering Service Option in writing within five business days after receiving such request. The Company's response shall include an explanation of the process and identify the Customer's prerequisites for commencing and completing the work. Once the Customer has completed the applicable prerequisites, the Company shall complete the work within 45 calendar days, or as promptly as working conditions permit.

The applicable Installation Charge, One-time Removal Charge, and On-going Monthly Charge for the Non-communicating Metering Service Option are as follows:

Non-communicating Metering Service Option(s) Installation, Removal, and On-going Charges for Non-communicating Meters			
Type	**Installation Charge**	**Removal Charge**	**On-going Monthly Charge**
Single-phase, 240 Volt, class 200	$84.53	$29.20	$29.20

The Company will own Non-communicating Meters used for measuring and billing the Customer for its consumption of energy. The Company is responsible for the installation and removal of all meters.

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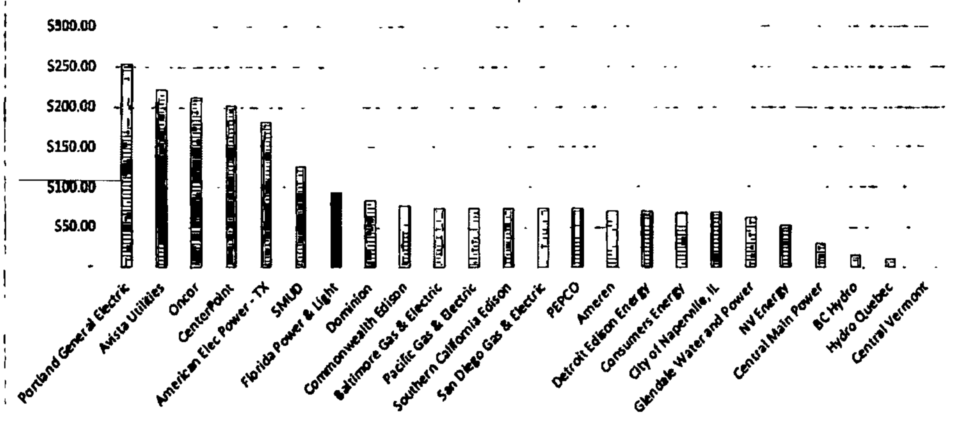
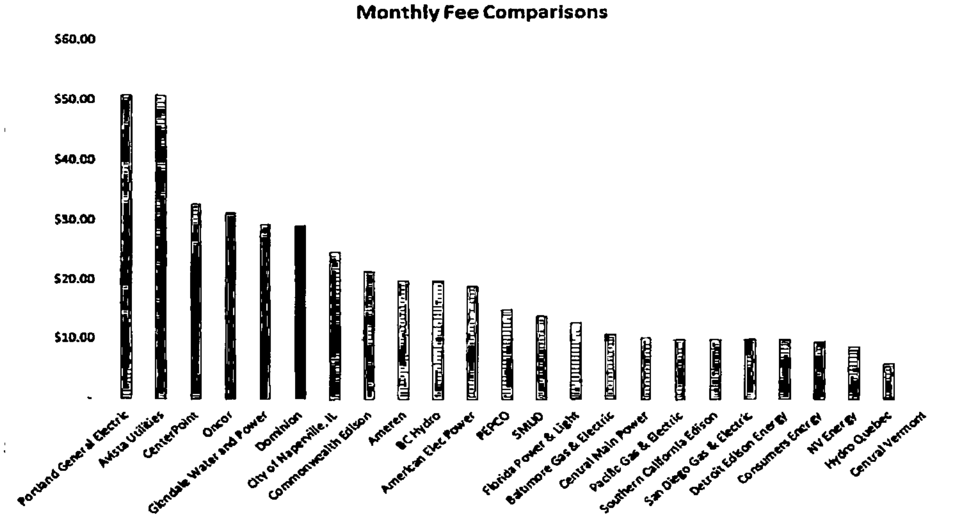
OPT-OUT FEE COMPARISON

Initial Fee Comparison



Monthly Fee Comparisons



Electric Vehicle Adoption Forecast

Counts (Cumulative)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	25,698	33,855	43,416	54,190	66,678	80,456	95,812	112,423	130,201	149,079	169,159
Navigant Low	18,754	22,296	26,837	32,329	39,147	47,078	56,368	66,860	78,473	91,159	105,010
Navigant High	29,906	41,781	55,409	70,528	87,754	106,564	127,296	149,607	173,280	198,144	224,332
MWh (Annual)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	88,499	116,589	148,806	184,755	226,103	271,322	321,431	375,245	432,661	493,590	558,432
Navigant Low	62,948	74,579	89,166	106,659	128,303	153,304	182,547	215,417	251,666	291,182	334,297
Navigant High	101,749	141,758	186,792	236,401	292,627	353,615	420,719	492,606	568,621	648,250	732,000
MW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Navigant Base	32	42	53	66	80	95	111	129	148	167	187
Navigant Low	23	27	32	38	45	53	63	74	86	98	112
Navigant High	37	51	67	84	102	123	145	168	192	217	243

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Alternative Fuels Data Center

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Printable Version

Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite

This tool provides a simple way to estimate how much electric vehicle charging you might need at a city- and state-level.

State | Vehicles | Results

Start Over

Your Results

In Virginia, to support 169,159 plug-in electric vehicles you would need.

3,778 Workplace Level 2 Charging Plugs

2,614 Public Level 2 Charging Plugs

There are currently 1,053 plugs with an average of 2.0 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

414 Public DC Fast Charging Plugs

There are currently 308 plugs with an average of 3.6 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

Where Do I Start?

Planners may want to prioritize installation of fast charging infrastructure above Level 2 charging.

Build DC Fast First: Establishing fast charging networks that enable long-distance travel, serve as charging safety nets, and provide charging for drivers without home charging is critical to support all-electric vehicles that have no other alternative for quickly extending their driving range.

Build Level 2 Second: EVI-Pro typically simulates the majority of Level 2 charging demand coming from plug-in hybrid electric vehicles, which have the ability to use gasoline as necessary for quickly extending driving range.

Change Assumptions

Plug-In Electric Vehicles (as of 2016): 7,300

Light Duty Vehicles (as of 2016): 7,231,000

Number of vehicles to support 169,159

Vehicle Mix

Plug-in Hybrids, 20-mile electric range	15	%
Plug-in Hybrids, 50-mile electric range	35	%
All-Electric Vehicles, 100-mile electric range	15	%
All-Electric Vehicles, 250-mile electric range	35	%
Total	100%	

How much support do you want to provide for plug-in hybrid electric vehicles (PHEVs)?

- ○ **Full Support** — *Most PHEV drivers wouldn't need to use gasoline on a typical day.*
- ◉ **Partial Support** — *Calculate using half of full support assumptions.*
- ○ **Do not count PHEVs in charging demand estimates.**

Percent of drivers with access to home charging 100 %

See all assumptions.

EV Adoption Forecast, Year 2030: 169,159

	New Charging Infrastructure Needed by 2030		
		Workplace Level 2 Ports	Public DC Fast Charging Ports
Row 1	Charging infrastructure needed to support forecasted adoption (Source: EVI-Pro Lite Tool):	3,778	414
Row 2	Less known existing charging infrastructure (Source: Alternative Fuels Data Center):	N/A	86
Row 3	New infrastructure needed by 2030 (Row 1 less Row 2):	3,778	328
Row 4	New infrastructure needed each year (Row 3 divided by 10 years):	378	33

	New Charging Infrastructure Needed during Phase 1B (2020-2021)		
Row 5	Two years of infrastructure - ports (Row 4 multiplied by 2)	756	66
Row 6	Two years of infrastructure - dual port charging stations (Row 5 divided by 2)	378	32.80

Existing Public Infrastructure (ports):	
Public DC Fast Charging	308
Public DC Fast Charging (No Restrictions)	86
Public Level 2	1,093
Public Level 2 (No Restrictions)	248
(No Restrictions) = No access requirements; available 24/7	

Company Exhibit No.
Witness: NJP
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ERCOT System Planning:

2018 Long-term System Assessment for the ERCOT Region
December 2018

Executive Summary

Section 39.904(k) of the Public Utility Regulatory Act (PURA) requires that the Public Utility Commission of Texas (PUCT) and Electric Reliability Council of Texas, Inc. (ERCOT) study the need for increased transmission and generation capacity, and report such needs to the Texas Legislature. A report documenting this study must be filed with the Legislature each even-numbered year.

By definition, the bulk transmission network within ERCOT consists of the 60-kilovolt (kV) and higher transmission lines and associated equipment. In planning for both the additions and upgrades to this infrastructure, ERCOT conducts a variety of forward-looking reviews to help ensure continued system reliability and efficiency.

ERCOT's planning process covers several time horizons to identify and endorse new transmission investments. The near-term needs are assessed in the six-year planning horizon through the development of the Regional Transmission Plan (RTP). The Long-Term System Assessment (LTSA) provides an evaluation of the potential needs of ERCOT's extra-high voltage (345-kV) system in the 10- to 15-year planning horizon.

The LTSA guides the six-year planning process by providing a longer-term view of system reliability and economic needs. Whereas in the six-year planning horizon a small transmission improvement may appear to be sufficient, the LTSA planning horizon may reveal that a more extensive project could be required. A larger project may also be more cost-effective than multiple smaller projects — each being recommended in successive RTPs.

ERCOT studies different scenarios in its long-term planning process to account for the inherent uncertainty of planning the system beyond six-years. The goal of using scenarios in the LTSA is to identify upgrades that are robust across a range of scenarios, or more economical than the upgrades that would be determined considering only near-term needs.

Members of the ERCOT Regional Planning Group (RPG) developed the following set of future scenarios through a series of stakeholder-driven scenario development workshops:

- Current Trends;
- High Economic Growth;
- High Renewable Penetration;
- High Renewable Cost; and
- Emerging Technology.

Using the assumptions and guidelines set by stakeholders in the scenario descriptions, ERCOT prepared different load forecasts.

Planning for transmission 10 and 15 years in the future requires ERCOT to make assumptions regarding what types of new resources can be developed. ERCOT conducted generation expansion and retirement analyses for the five future scenarios using the guidelines set by stakeholders in the scenario descriptions, including a detailed transmission expansion analysis based on current trends (Current Trends scenario).

Based on the results of the analyses that went into the 2018 LTSA, ERCOT made the following key findings:

- All five scenarios showed a significant amount of solar generation additions, ranging from 3,900 megawatts (MW) to 15,100 MW. Two scenarios showed some retirement of coal and gas generation. Higher amounts of wind and gas generation additions were also seen compared to previous LTSA studies.
- The scale of solar generation additions is dependent upon access to the solar-rich sites in the Far West Texas region.
- There may be generation capacity challenges during summer in the hours ending 2000 to 2200 in scenarios with a large amount of solar generation.
- The Emerging Technology scenario, which reflected an assumed high adoption rate in the electrification of the transportation sector in Texas, showed a significant change in the load profile. For instance, the peak hour of the day shifted from hour ending 1700 to 2200 in the night and the magnitude of this peak was also approximately 15% higher than conventional load. The load profile and generation expansion implications of the changing load shape in this scenario suggest that EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.
- Expected continued generation additions in the Far West region will necessitate transmission improvements in the area to allow exports of solar and wind generation to ERCOT load centers. Specifically, new transmission lines between West Texas and San Antonio, and between the Far West and West weather zones were found to be economically viable.

In all five scenarios, a mix of solar, wind and gas generation was added to the system to serve growing demand and replace retired capacity. Solar generation additions represented the largest resource capacity change on the system in three of the five scenarios. As seen in Figure ES.1, total utility-scale solar generation capacity additions ranged from 3,900 MW to 15,100 MW in the five scenarios. Conversely, two of the five scenarios had varying levels of coal and gas generation retirements.

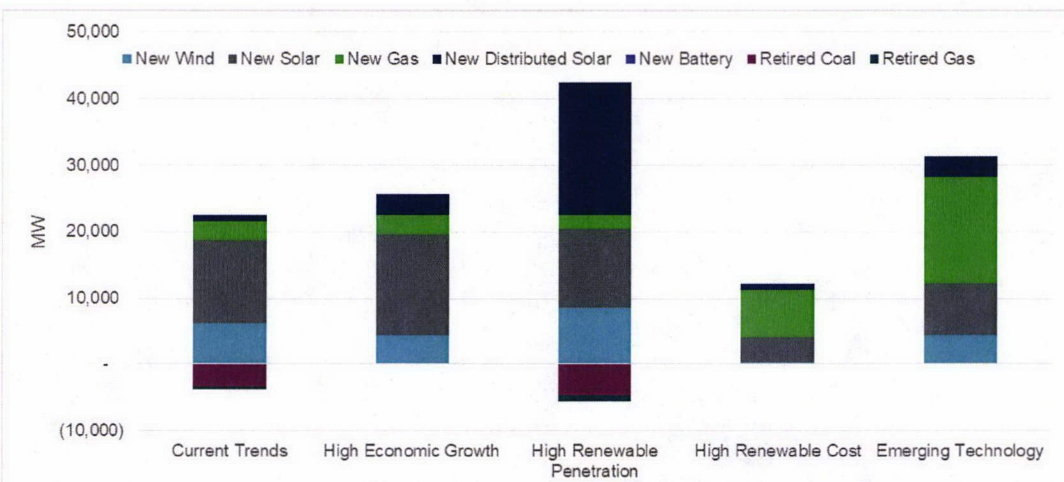


Figure ES.1: Capacity Additions and Retirements across All Scenarios

The 2018 LTSA capacity expansion modeling results indicate a potential operational challenge due to capacity shortages in summer evenings when solar generation ramped down. This same potential generation capacity challenge was found in the 2016 LTSA modeling results. While the generation capacity shortage occurred in a relatively small number of hours, these modeling results indicate that conventional peaking generation units, such as combustion turbines, may not be able to recover investment costs to serve the evening peak demand. To meet this net peak demand requirement, other resources will need suitable ramping capabilities and be financially viable even though they could only be operated a limited number of hours each year.

In the Emerging Technology scenario, based on the assumed charging patterns and assumed high EV adoption in Texas, the total peak charging demand was estimated to be over 18,500 MW at midnight. Approximately 5,000 to 6,000 MW of charging demand was expected for hours ending 1600 through 1800. As a result of this increase in demand and changed load shape, the generation expansion model added approximately 9,000 MW more new generation capacity than in the Current Trends scenario. The Emerging Technology scenario also reflected fewer generation retirements than the Current Trends scenario. High charging demand primarily occurred at night when solar generation is not available. As a result, the Emerging Technology scenario showed the most new gas generation among all scenarios studied.

One sensitivity case, in which EV adoption was assumed to be 50% of that in the Emerging Technology scenario, was developed to investigate the relationship between generation expansion results and adoption level of EVs. Figure ES 2 shows the generation expansion model results for generation capacity additions by type and retirements for the Current Trends scenario, the Emerging Technology scenario, and the Emerging Technology scenario sensitivity case. The Emerging Technology scenario sensitivity case generation expansion results were approximately midway between the Current Trends and Emerging Technology scenario results in terms of gas and solar generation additions and generation retirements. Thus, the sensitivity showed a positive correlation between EV adoption, gas generation additions, and generation retirements, and a negative correlation with solar generation additions.

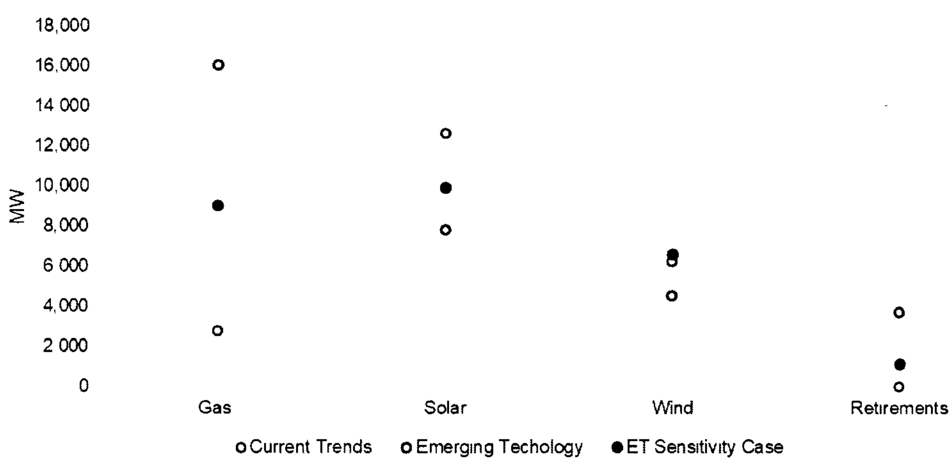


Figure ES.2: Generation Capacity Additions by Type and Retirements for Current Trends Scenario, Emerging Technology Scenario, and Emerging Technology Scenario Sensitivity Case

The addition of solar generation in the western part of the state coupled with the retirement of coal and gas generation in the eastern part of the state could result in significant increases in west-to-east power flows on the transmission system. This outcome was noted in the results from the transmission expansion analysis.

The observed west-to-east power flows resulted in the need for transmission system improvements including existing 345-kV upgrades and new extra high voltage paths in order to reliably deliver power to the load centers. Figure ES.3 highlights some of the significant transmission improvements needed in the Current Trends scenario.

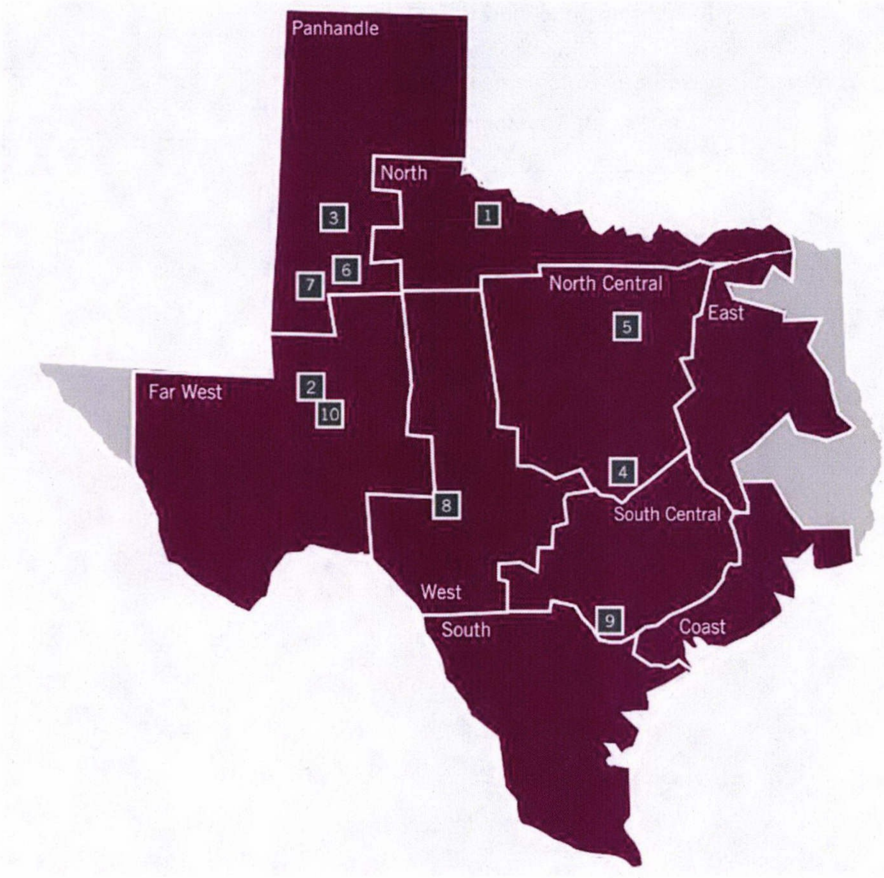


Figure ES.3: Transmission Additions Identified for Current Trends Scenario

Table ES. 1: Transmission Upgrades and Additions

Index	Projects	In service date
1	Oklaunion to Jacksboro new 345-kV line	2028
2	Odessa to Bearkat new 345-kV line	2028
3	Lubbock Loop (North to New Oliver new 345-kV line and Long Draw to Grassland 345-kV line upgrade)	2028
4	Northwest Austin Metro new 345-kV line and 345/138-kV transformer	2028
5	Northwest Dallas-Fort Worth new 345-kV line	2028
6	Faraday to Morgan Creek new 345-kV line	2028
7	Long Draw to Dermott new 345-kV line	2028
8	West Texas to San Antonio new 345-kV line	2028
9	Bergheim 345/138-kV transformer upgrade	2028
10	Odessa to Moss new 345-kV line	2033

Contents

Chapter 1. Introduction

ERCOT is a membership-based 501(c)(4) nonprofit corporation, subject to PUC oversight. In 1999, the Texas Legislature restructured the Texas electric market and assigned ERCOT the responsibilities of maintaining system reliability through both operations and planning activities, ensuring open access to transmission, processing retail switching to enable customer choice, and conducting wholesale market settlement for electricity production and delivery.

In fulfilling these responsibilities, ERCOT manages the flow of electric power to more than 25 million Texas customers — representing about 90 percent of the state's electric load. ERCOT schedules power on an electric grid that connects over 46,500 miles of transmission lines and more than 600 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for customers in competitive choice areas.

As part of its responsibility to adequately plan the transmission system, ERCOT must develop a biennial assessment of needed transmission infrastructure. As noted above, PURA § 39.904(k) requires the PUCT and ERCOT to study the need for increased transmission and generation capacity throughout the state of Texas, and report to the Legislature the results of the study and any recommendations for legislation. The report must be filed with the Legislature no later than December 31 of each even-numbered year. In furtherance of this requirement, ERCOT develops the following reports:

- Annual Report on Constraints and Needs in the ERCOT Region - Assessment of the need for increased transmission and generation capacity for the upcoming six years; Summary of the ERCOT RTP to meet those needs.
- Biennial LTSA for the ERCOT Region - Analysis of the system needs for a long-term 10 – 15 year planning horizon designed to guide near-term decisions.

Together, these reports provide an assessment of the needs of the ERCOT system for the upcoming 15 years. Given the long-term nature of the study horizon, the findings and observations from the LTSA are based on analysis of multiple scenarios. Such scenarios developed through collaborative effort between ERCOT and stakeholders and are based on projections of certain key assumptions. The LTSA projections, specifically load, generation, and transmission expansion plans, are outcomes of these scenario-specific studies, and should not be considered ERCOT's official forecasts for the long-term horizon.

Chapter 2. LTSA Process

The process of planning a reliable and efficient transmission system for the ERCOT region is composed of several complementary activities and studies. The ERCOT-administered system planning activities comprise near-term studies (e.g., the RTP, RPG projects), and ongoing long-range studies, which are documented in the LTSA. In addition to these activities, transmission service providers (TSPs) conduct analyses of local transmission needs supplemental to the ERCOT planning process.

The LTSA process is based upon scenario analysis techniques to assess the potential needs of the ERCOT system for up to 15 years. The role of the LTSA is to provide a roadmap for future transmission system expansion, and identify long-term trends to be considered in near-term planning.

The LTSA guides analysis in the near-term study horizon through scenario-based assessment of divergent future outcomes. As future study assumptions become more certain, the RTP supports actionable plans to meet near-term economic- and reliability-driven system needs. In support of stakeholder-identified or ERCOT-assessed projects, the RPG review process leads to the endorsement of individual projects that maintain reliability or increase system economy. Collectively, these activities create a robust planning process to ensure the reliability and efficiency of the ERCOT transmission system for the foreseeable future.

The LTSA is a composite study made up of various processes and analyses such as scenario development, generation expansion analysis, load forecasting analysis, and transmission expansion analysis. ERCOT uses a scenario-based approach to perform the LTSA. The purpose of the scenario-based approach is to provide a structured format for stakeholders and ERCOT to identify the most critical trends, drivers, and uncertainties over a ten- to fifteen-year period. Scenarios developed through stakeholder workshops provide high level guidelines for preparing cases to be used in the LTSA. In addition to the scenarios, stakeholders identified additional sensitivities for some of the scenarios. The sensitivities were created by varying a key input assumption used in the scenario. The scenario descriptions were converted to modeling assumptions using available reference data. In addition, for each scenario, a scenario-specific demand forecast was created using inputs from the scenario descriptions.

The demand forecast and other scenario specific generation input assumptions such as capital cost, operation and maintenance costs, emission costs, etc. were used to create each generation expansion plan. These plans describe the total amount of generation additions by technology. The plan also identify any retirements required as a result of the scenario descriptions. The generation additions were later added to transmission study models using the generation siting process as documented in the generation siting methodology.[1] The LTSA culminated in a transmission expansion analysis which involved evaluating the potential needs for the ERCOT grid under different load and generation assumptions as developed during the load forecasting and generation expansion planning stages. Figure 1 provides a summary of the LTSA process. A detailed description of analyses and studies that went into the LTSA can be found in Appendix I.

[1] The LTSA Generation Siting Methodology is attached in Appendix III

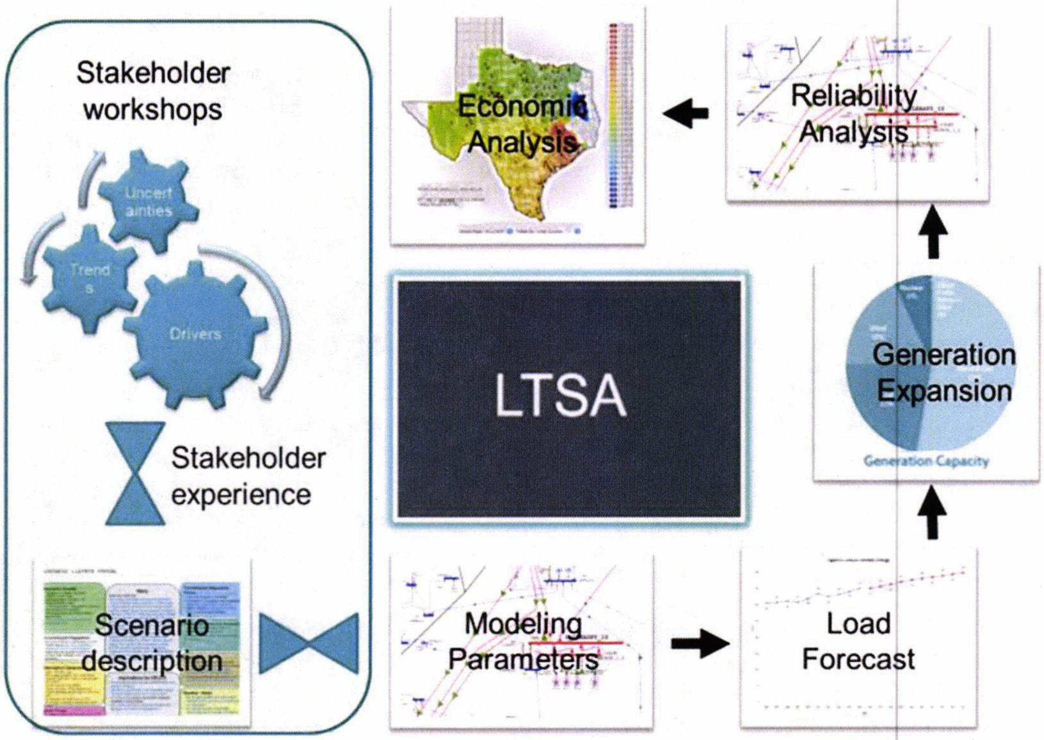


Figure 4: 2018 Long-Term System Assessment Process

Stakeholders identified five scenarios to be included in the 2018 LTSA. Table 1 below provides a summary of the each scenario.

Table 1: Scenarios Identified for the 2018 LTSA

Scenario	Description
Current Trends	The Current Trends scenario was designed to study the trajectory of what is known and knowable today (e.g., liquefied natural gas (LNG) export terminals, Texas growth, low gas and oil prices). Notably, a significant shift in assumptions for the Current Trends scenario was found with respect to environmental regulations. Unlike the 2016 LTSA, the 2018 LTSA assumed the Regional Haze Program and Cross-State Air Pollution Rule (CSAPR) would not be active. The following sensitivities were performed in this scenario: • High gas prices using the Annual Energy Outlook (AEO) 2018 referenced gas prices;[2] and • Wind and solar generation siting restrictions due to transmission availability consideration.
High Economic Growth	The High Economic Growth scenario looked at significant population and economic growth from all sectors of the economy (i.e., residential, commercial and industrial). This scenario also included assumed sustained increase in oil and gas loads in West Texas, along with development of additional LNG export terminals.
High Renewable Penetration	The High Renewable Penetration scenario found that favorable federal policies and reduction in overnight capital cost for renewable technologies (e.g., solar and wind) would result in a high penetration of renewables on the ERCOT grid. This scenario assumed higher levels of distributed solar adoption. The following sensitivities were identified in this scenario: • Higher limit on annual solar additions; and • Wind and solar generation siting restrictions due to transmission availability consideration and higher limit on annual solar additions.
High Renewable Cost	The High Renewable Cost scenario studied the effects of an accelerated phase-out of renewable subsidies, and a moderate increase in overnight capital cost of renewable technologies.
Emerging Technology	The Emerging Technology scenario was designed to study the effect of rapid electrification of the transportation sector in Texas. The following sensitivities were identified in this scenario: • Lower EV adoption scenario (50% of base scenario); and • High distributed solar adoption (20,000 MW).

[2] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2018&cases=ref2018&sourcekey=0

Chapter 3. Key Findings

The 2018 LTSA includes a study of five different scenarios. In addition, sensitivity analysis was performed on three of the five scenarios to gain deeper insights into the scenarios. This section outlines the following key findings from the study:

1. Significant amount of solar generation additions were found in all five scenarios;
2. Increased adoption of electric vehicles could result in a significant shift in hourly load profile, while increasing demand;
3. The scale of solar generation additions is dependent upon transmission access to the solar-rich sites in the Far West Texas region; and
4. Significant transmission improvements are needed for exports of solar and wind generation from West Texas to ERCOT load centers.

Key Finding 1: Significant amount of solar generation additions found in all five scenarios

The generation expansion analysis found that older coal and gas generation was displaced by wind, solar and more efficient gas generation technologies. The penetration level of solar generation increased in all scenarios. However, gas generation remains the primary technology used to meet ERCOT load throughout the five scenarios. These findings are generally consistent with the results from the 2016 LTSA, but more wind and gas capacity was added in the 2018 LTSA.

One reason more wind capacity was added in the 2018 LTSA is the new Direct Current (DC) Tie capacity included in this analysis. The model results showed that the additional DC tie capacity would encourage more wind generation additions because wind generation could be exported across the DC ties during periods of low prices in ERCOT.

The increase in gas capacity in the 2018 LTSA can be partially linked to lower gas price projections. The lower gas price assumptions in the 2018 LTSA would likely encourage more gas capacity additions, which could lead to some coal retirements.

Another factor driving the difference in results between the 2016 and 2018 LTSAs is that a new software tool used in the 2018 LTSA generation expansion analysis was able to capture the value of solar and wind generation more realistically than what was used in the 2016 LTSA.

Capacity Additions

Total capacity added by the model varied from 11,200 MW in the High Renewable Cost scenario to 28,300 MW in the Emerging Technology scenario. Utility-scale solar capacity additions ranged from 3,900 MW to 15,100 MW across the scenarios. The amount of distributed solar generation added in each scenario was a model input rather than a results of economic analysis. The assumed distributed solar adoption varied from 1,000 MW to 20,000 MW. Utility-scale solar dominated capacity additions in all scenarios except the Emerging Technology scenario and the High Renewable Cost scenario, because the assumed capital cost of solar generation was low enough, such that the investment could be recovered by energy prices. However, the Emerging Technology scenario included a significant amount of EV charging at night, which biased the model to select resources that are available at night. In the High Renewable Cost scenario, the solar capital cost was assumed to be higher than the other scenarios, and the annual solar capacity addition limit was lowered to 300 MW, which limited the solar capacity addition in the High Renewable Cost scenario. Figure 2 shows the amount of capacity added in each scenario.

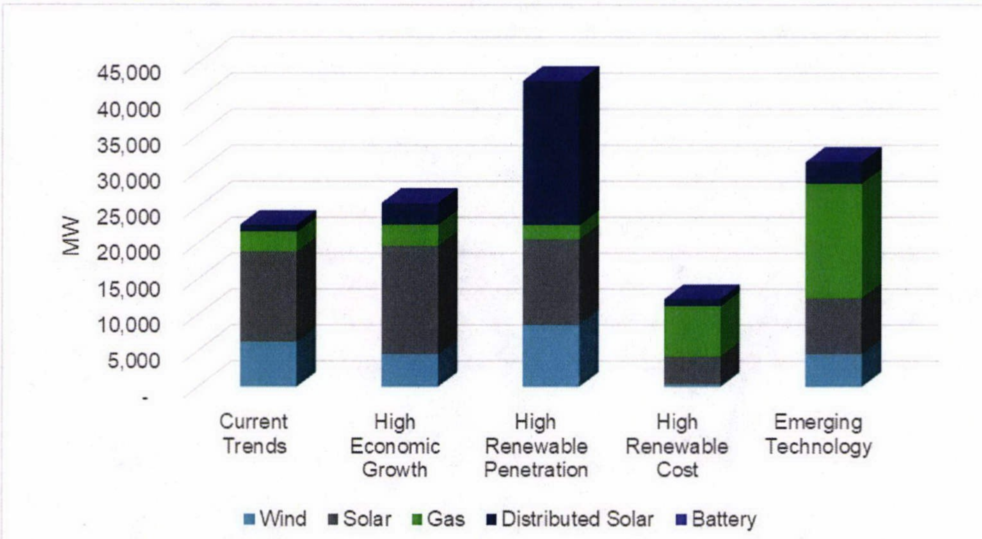


Figure 5: Generation Capacity Additions by Scenario

Generation Retirements

Generation retirements were limited to coal and gas steam units. In the 2016 LTSA, coal units affected by environmental regulations under the Regional Haze Program were assumed to be retired in all scenarios. However, in the 2018 LTSA, the model retired only those generators that could not recover its variable and fixed costs, and as a result, the total retired capacity varied by each of the five scenarios. The High Economic Growth, Emerging Technology and High Renewable Cost scenarios had no generation retirements. There were no retirements in the High Economic Growth scenario and the Emerging Technology scenario because fast load growth was shown to improve the economics of existing generators. There were no retirements in the High Renewable Cost scenario because renewable generation had higher assumed capital costs. Notably, the model was restricted from adding more than 300 MW of solar generation, and 600 MW of wind generation, on an annual basis, thereby decreasing competition for existing generators. The High Renewable Penetration scenario had the highest amount of generation retirements (i.e., 5,610 MW), in part due to the assumption of 20,000 MW of distributed solar coupled with a high carbon tax assumption (e.g., 25 $/ton) throughout the study period. The retired capacity was replaced by wind, solar and more efficient gas generation. Figure 3 shows the amount of capacity retired in each scenario.

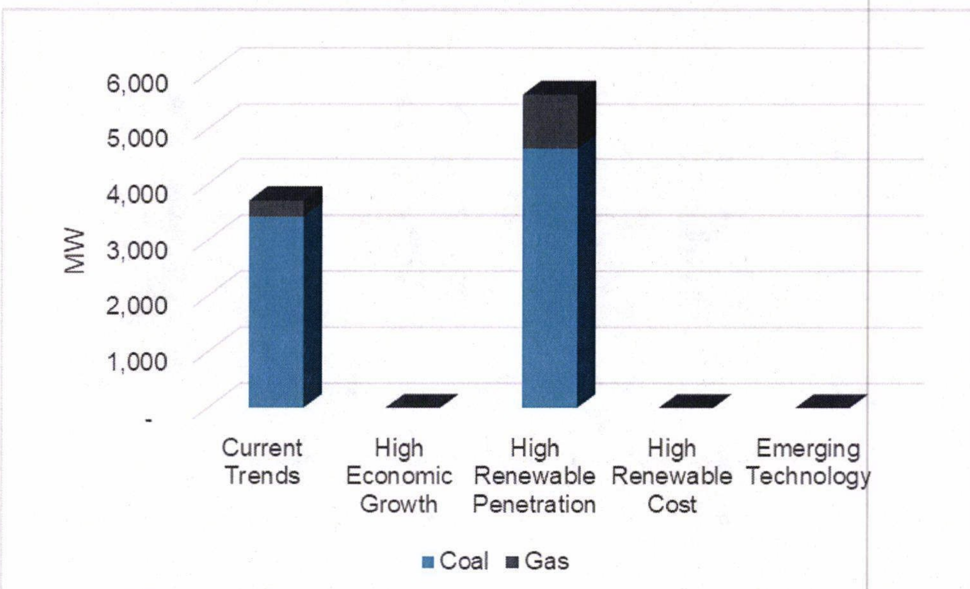


Figure 6: Generation Capacity Retirements by Scenario

The share of load served by coal generation declined in four out of the five scenarios due to coal retirements and low gas prices making coal generation less competitive. Retired coal generation was replaced by solar, wind and gas generation. The share of solar generation increased in all five scenarios, driven by the solar capacity additions. Gas remained the primary fuel used to serve ERCOT load throughout the scenarios. Figure 4 shows the percent of total energy generated by fuel type in 2033 for all scenarios.

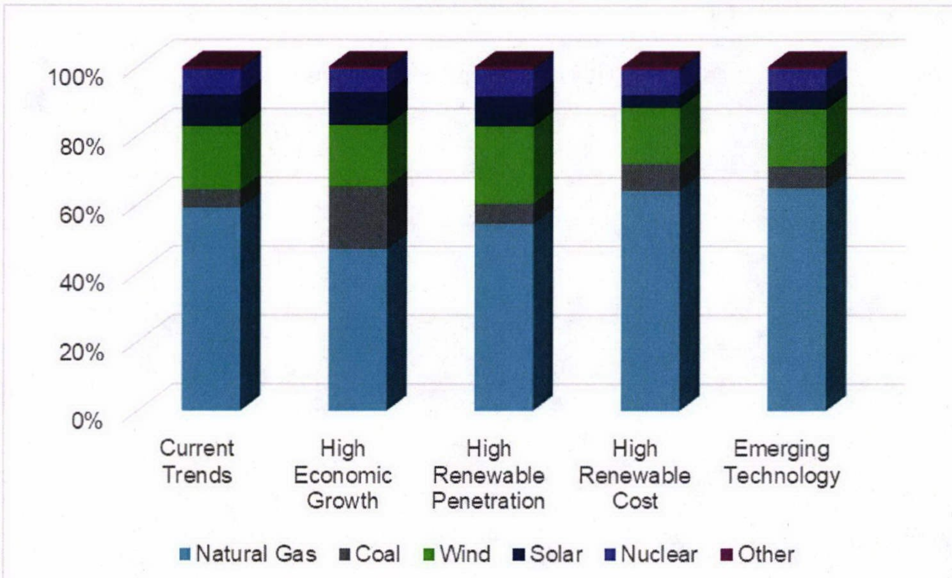


Figure 7: Generation by Fuel Type in 2033

Net-load Peak

A comparison net load and conventional demand from the Current Trends scenario in year 2033 is shown below in Figure 5. The net load curve is developed by calculating the balance of load that will be served after intermittent generation (e.g., wind and solar) is utilized. The peak load portion of the net load duration curve is steeper than the conventional load duration curve. The net load peak occurs in a relatively small number of hours, and therefore, investors in conventional peaking generation capacity (e.g., combustion turbines) may not be able to recover investment costs to meet the net peak demand, and other resources will be necessary to serve the net peak demand requirement. Such resources will require suitable availability and ramping capabilities.

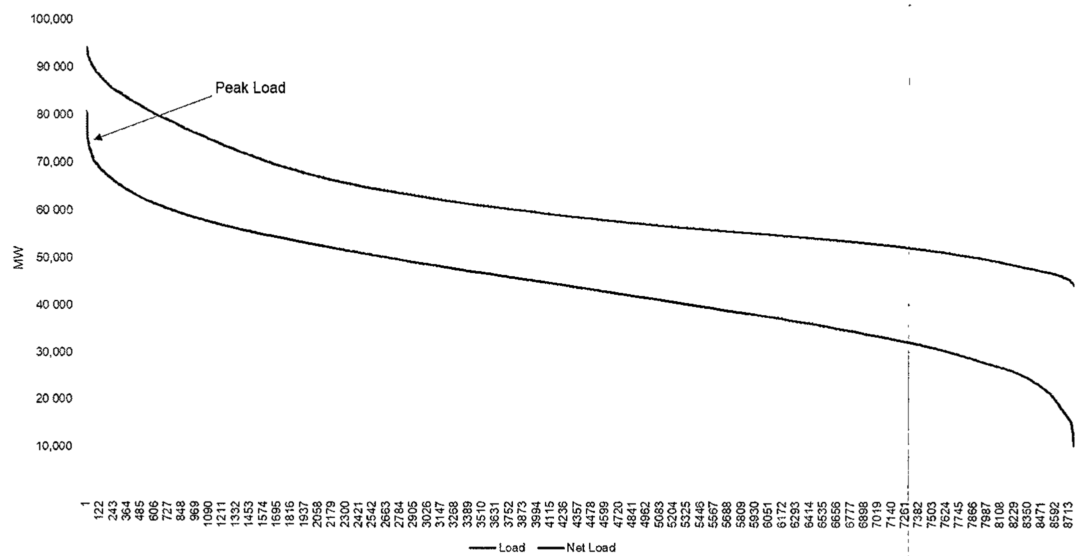


Figure 8: Load vs Net Load for Current Trends Scenario in 2033

Key Finding 2: Increased adoption of electric vehicles could result in a significant shift in hourly load profile, while increasing demand

Background

Stakeholders developed the Emerging Technology scenario to highlight the potential long-term impacts of extensive transportation electrification on the ERCOT grid. Based on the assumed charging patterns and high EV adoption in Texas, the total peak charging demand was estimated to be greater than 18,500 MW (occurring at midnight). Approximately 5,000 - 6,000 MW of charging demand between hours ending 1600 and 1800. As a result of this increase in demand and change in load shape, the generation expansion model added approximately 9,000 MW more new generation capacity than in the Current Trends scenario. The Emerging Technology scenario also included fewer generation retirements than the Current Trends scenario. High vehicle charging demand primarily occurred at night when solar generation is not available. As a result, the Emerging Technology scenario had the most new gas generation among all scenarios.

Load Profile Impacts

ERCOT reviewed traffic flow information from the Department of Transportation,[3] to estimate the adoption of EVs by 2033— see Table 2. The electricity consumed by every vehicle was estimated based on an assumed daily driving distance.

Table 2: EV Penetration and Charging Demand Estimation for Emerging Technology Scenario

Type	Number of Vehicles in 2033	Per Vehicle Charging (kWh)	Peak Charging Demand (MW)
Cars	3,000,000	20	5,940
Short Haul/Buses	80,000	350	2,800
Long Haul Trucks	200,000	600	10,200

[3] https://www.txdot.gov/inside-txdot/division/transportation-planning/maps/statewide-2016.html

The charging patterns and demand flexibility will likely vary among different types of EVs. For this study, most cars were assumed to charge overnight so that they would be fully charged before hour ending 0500, trucks and buses were assumed to charge around noon and again overnight. Figure 6 shows the assumed normalized average hourly charging pattern of EVs by type.

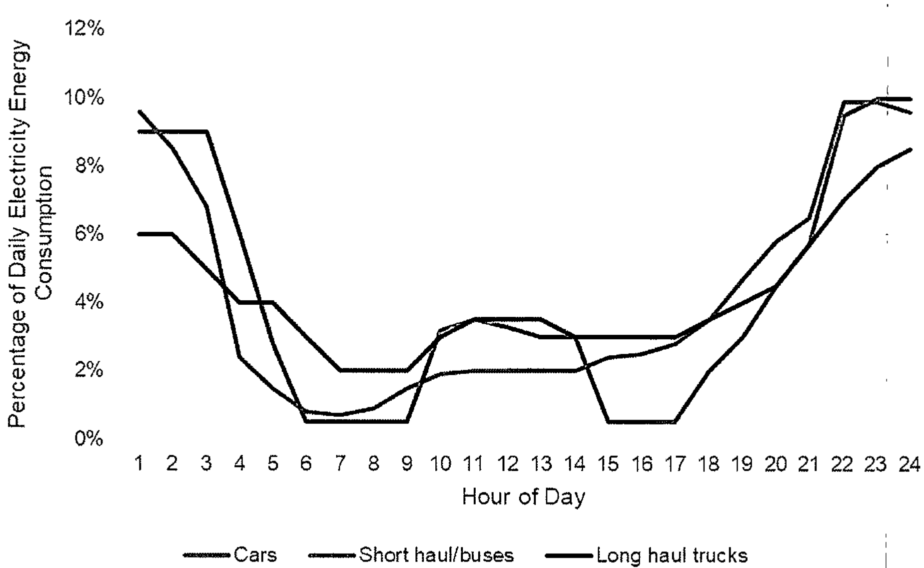


Figure 9: Assumed Hourly Charging Patterns by Vehicle Type

For 2033, the total peak charging demand is estimated to be over 18,500 MW at midnight. Approximately 5,000 to 6,000 MW of charging demand was expected during hours ending 1600-1800. In this scenario, the system-wide summer peak would occur around hour ending 2200. Figure 7 shows the aggregated charging demand by vehicle type.

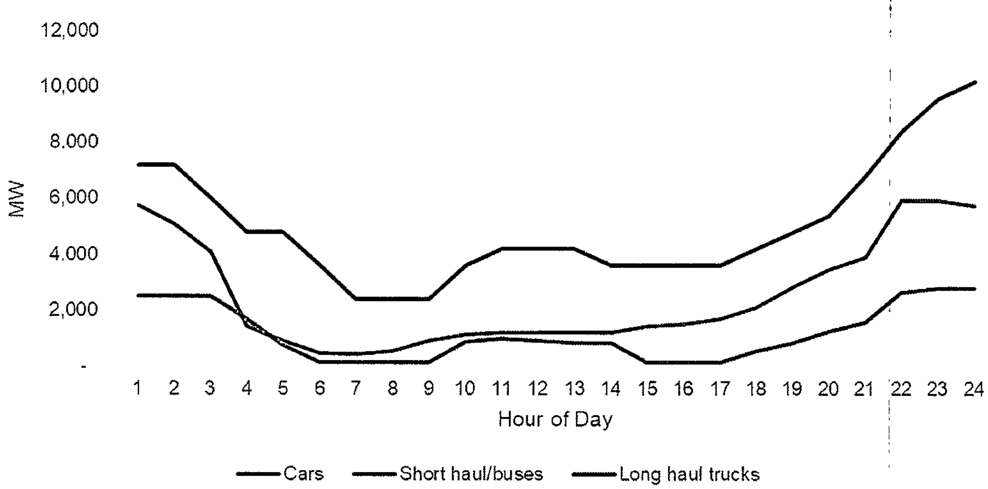


Figure 10: Estimated Total Charging Demand of EVs by Type in 2033

Figure 8 below shows the impact of EV charging on a hot summer day in 2033, where the daytime peak hour shifts from hours ending 1600-1800 to hour ending 2200 at night.

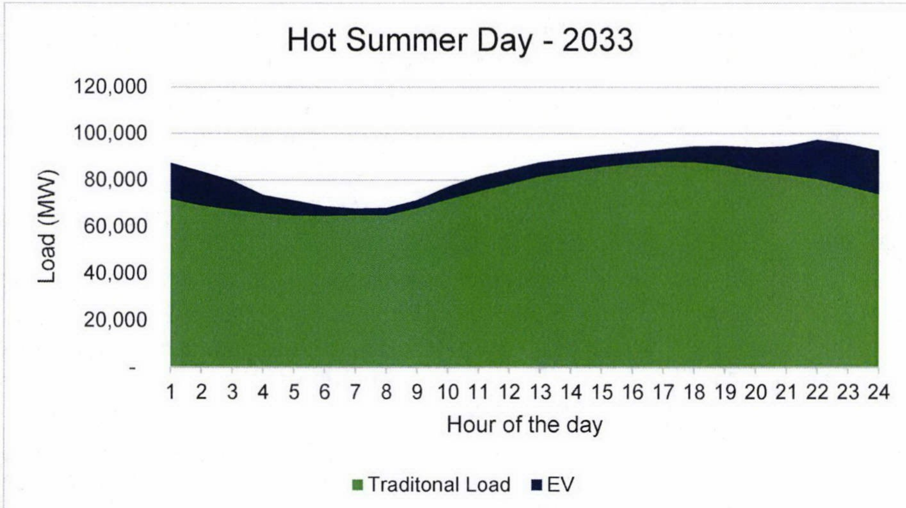


Figure 11: A Sample Hot Summer Day in 2033 with Low Distributed Solar Penetration

Figure 9 below shows the impact of EV charging on a hot summer day in 2033 with high distributed solar penetration. In this scenario, the magnitude of the peak is approximately 16% higher than load at the traditional peak hour. Given that both distributed solar generation and EV charging behavior is currently not controlled by grid operators, this scenario may pose resource adequacy and operational challenges.

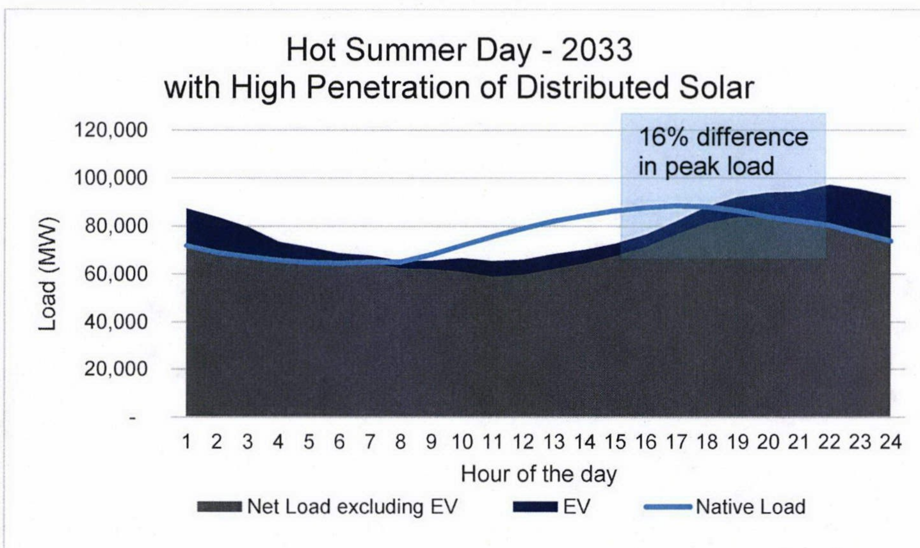


Figure 12: A Sample Hot Summer Day in 2033 with High Distributed Solar Penetration

Generation Expansion Considerations

The following sensitivity cases were completed for the Emerging Technology scenario·

- Sensitivity 1 - 20,000 MW of distributed solar capacity was added to determine how this change would affect the overall addition of generation resources; and
- Sensitivity 2 - EV adoption was reduced to be 50% of the base scenario to investigate the relationship between EV adoption level and generation capacity expansion.

The generation expansion model added 12,100 MW gas capacity, and 50 MW biomass capacity for Sensitivity 1. The generation expansion model included 3,900 MW less in gas capacity, 7,800 MW less in utility scale solar, and 4,500 MW less in wind capacity than the Emergency Technology base scenario. The increased penetration of distributed solar created a net load shape that peaked around hour ending 2200. The sensitivity case indicated 97 potential scarcity hours in 2033 occurring between hours ending 2000 and 2400. The net load peak issue is the same as described in Key Finding 1. The generation expansion results of Sensitivity 1 suggest that EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.

The generation expansion model included 7,000 MW less in gas capacity, 2,100 MW more in wind capacity, and 2,100 more in solar capacity for Sensitivity 2. The generation expansion model retired 1,116 MW capacity (compared to no retired capacity in the Emerging Technology base scenario). Figure 10 below shows the generation expansion model results for generation capacity additions by type, and retirements for the Current Trends scenario, the Emerging Technology scenario, and Emerging Technology scenario for Sensitivity 2. The Emerging Technology scenario Sensitivity 2 results were approximately midway between the results for the Current Trends and Emerging Technology scenarios in terms of gas and solar generation additions and generation retirements. Thus, Sensitivity 2 indicated a positive correlation between EV adoption, gas generation additions, and generation retirements, and a negative correlation with solar generation additions.

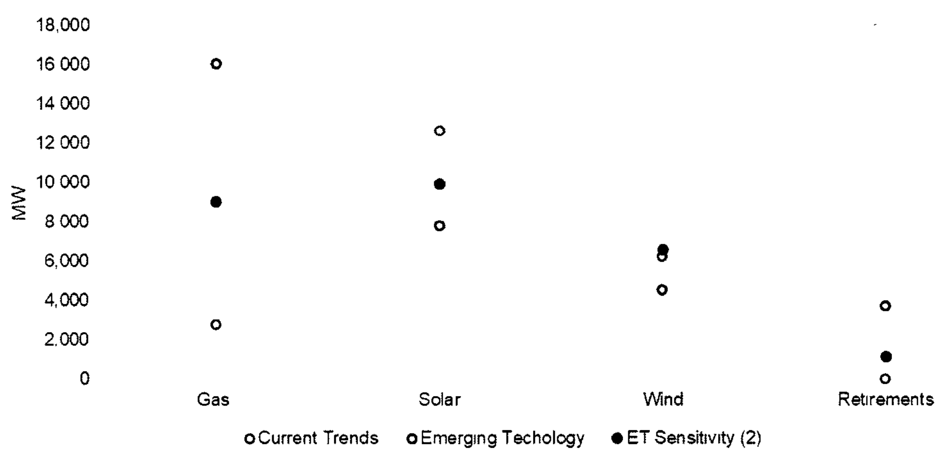


Figure 13: Generation Capacity Additions by Type and Retirements for Current Trends scenario, Emerging Technology Scenario, and Emerging Technology Scenario for Sensitivity 2

Key Finding 3: The scale of solar generation additions is dependent upon transmission access to the solar-rich sites in the Far West Texas region

Background

One of the limitations of projecting the future generation mix using regional economic models is the omission of transmission constraints and future transmission build out patterns. The generation expansion model's decision-making process does not include all factors considered by developers such as availability of favorable transmission points of interconnections. Such limitations result in the model favoring the most economical resource purely based on capital costs and future energy price projections. One way of incorporating transmission limitations in the generation expansion process would be to include transmission interface limits in the model input, but such an approach unrealistically assumes that no transmission upgrades will be made in the future and thus results in a sub-optimal generation mix projection. ERCOT addressed this concern by including information from the ERCOT generation interconnection queue. The interconnection queue serves as a proxy in an attempt to incorporate aspects of a generation developer's decision-making process. Specifically, the queue indicates which counties and sites are considered favorable for particular technologies.

Generation Expansion Comparison

A generation expansion sensitivity was considered for the Current Trends scenario. First, the model was add generation capacity with no locational restrictions, and sites from all Texas counties were included. Second, as a sensitivity, the model was restricted to only allow solar and wind generation additions in counties that currently have generation development interest, based on the generation interconnection queue. As shown in Table 3 below, noteworthy differences in the generation siting mix were observed between the two cases.

Table 3: Siting Comparison between Current Trends Scenario and Generation Expansion Assumption Alternatives

Current Trends Generation Expansion with County Limitation (MW)				
Weather Zone	Gas	Solar	Wind	Total
Far West	-	9200	500	9700
North	-	1600	5000	6600
West	-	1900	900	2800
N/A	2750	-	-	2750
Total	2750	12700	6400	21850
Current Trends Generation Expansion with No County Limitation (MW)				
Weather Zone	**Gas**	**Solar**	**Wind**	**Total**
Far West	-	14000	600	14600
North	-	300	1900	2200
West	-	500	200	700
N/A	6500	-	-	6500
Total	6500	14800	3200	24500

As noted in Table with locational restrictions, the generation expansion showed less new solar and gas generation capacity.

In addition to differences in the amount of generation capacity added, the location of new generation also changed between the cases, as shown in Figure 11 below. Figure 11 shows the difference in the amount renewable generation added by county between the two cases. The counties shaded purple identified more generation in the case with no county limitations, whereas the counties shaded blue identified more generation in the case with county limitations. Notably, solar generation added to the westernmost regions of Texas was substantially reduced when county limitations were applied. These results indicate that the amount of solar generation added in the future may depend on transmission availability in the solar-rich areas of the state.

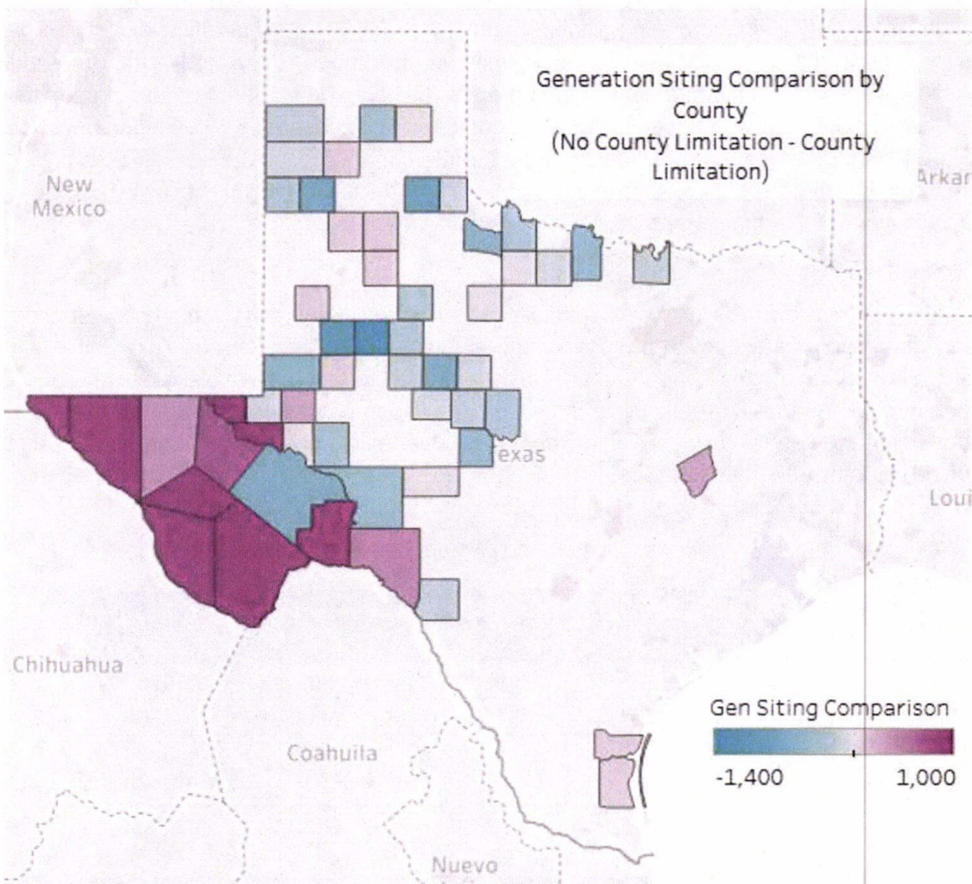


Figure 14: Renewable Generation Siting Comparison by County (MW in 2033)

Key Finding 4: Significant transmission improvements needed for exports of solar and wind generation from West Texas to ERCOT load centers

The transmission expansion analysis identified a need for additional transmission paths to West Texas to deliver additional wind and solar generation to ERCOT's major load centers in the eastern part of the state. For all five scenarios, the expectation is a significant rise in solar generation in the Far West region. Therefore, ERCOT also studied transmission limitations from the Far West region. Transmission analysis indicated a Far West voltage stability export limitation of 4,046 MW for summer peak conditions, and 3,867 MW for off-peak load conditions. Thus, new export paths from the Far West region will likely be needed to transfer power to load centers in the eastern part of the state.

Figure 12 below shows the map of top congested elements in year 2028 of the Current Trends scenario before any transmission improvements were added. The sizes of the circles indicate the relative amount of congestion rent.

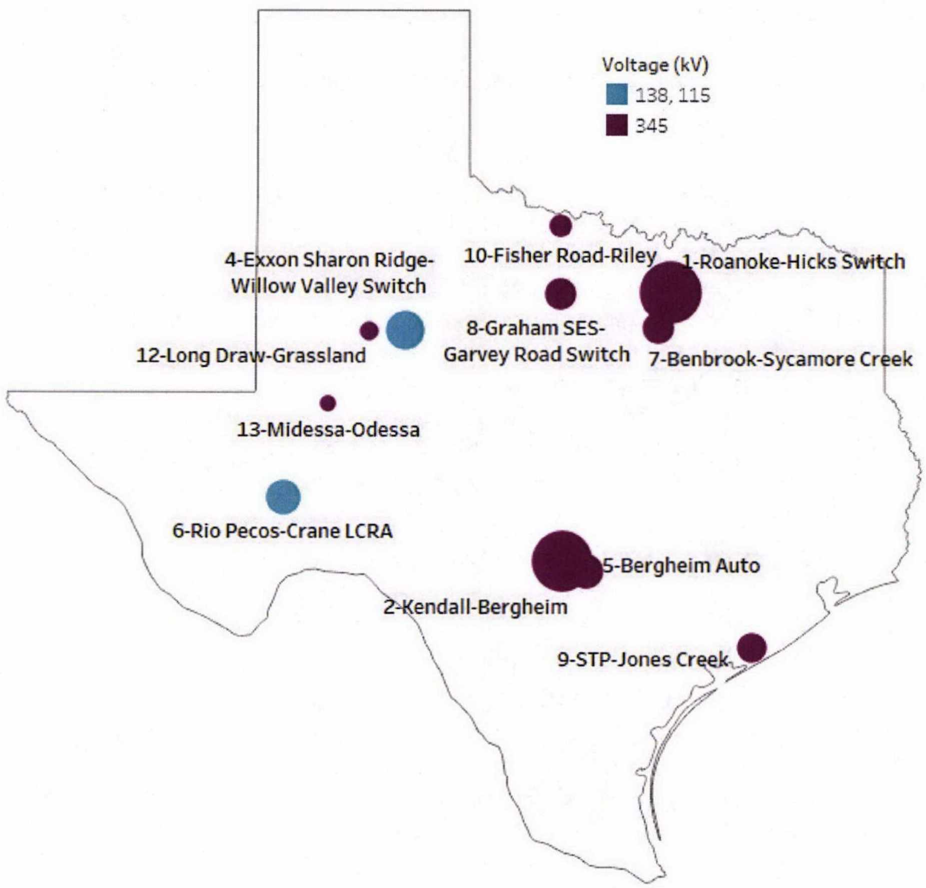


Figure 15: Current Trends Scenario (2028 model) - Top Congested Elements (Before Upgrades)

Notable congestion was observed on the 115-kv system in the Lubbock County, along the transmission path between the Panhandle and the northwest Dallas-Fort Worth area, and northwest of San Antonio, near Kendall County.

In the Lubbock region, the contingency loss of the Wadsworth-Oliver 345-kV line connecting Lubbock to ERCOT results in congestion on the 115-kV network of Lubbock. As a result, additional 345-kV transmission paths around the Lubbock system would be required to alleviate congestion on the 115-kV Lubbock system. This observation is consistent with the findings included in ERCOT's study of the Integration of the Lubbock Power & Light System into the ERCOT System.[4]

In the north, heavy congestion was seen along the path between the Panhandle and the Dallas-Fort Worth area. This observation is consistent with findings from the 2018 RTP in the near-term planning horizon and recent real-time congestion patterns during high-wind periods. Specifically, high congestion rents were observed on the Hicks-Roanoke Switch 345-kV line, Benbrook Switch-Sycamore Creek 345-kV lines, Fisher Rd-Riley 345-kV line and Graham SES-Garvey Rd Switch 345-kV line. Studies showed that 345-kV transmission additions near the northwest portion of the Dallas-Fort Worth area and upgrades of existing transmission lines in the area would show sufficient production cost savings to justify the projects while addressing some of the congestion identified in the region.

The congestion that was observed in the model in the Kendall region is also evident in the near-term planning studies. Wind and solar generation from the West and Far West regions of Texas flow to San Antonio, Houston, and the Lower Rio Grande Valley via the Big Hill-Kendall 345-kV line. An increase in this west-to-south transfer results in heavy congestion on the network connected to the Kendall region. Specifically, the Kendall-Bergheim 345-kV line and Bergheim 345/138-kV transformers had congestion rent of approximately $450M in the 2028 model. In addition, a significant amount of new solar generation in Pecos County was shown to be heavily curtailed. Several transmission improvements that add an additional path between West Texas and San Antonio were tested and found to address the congestion near Kendall, thereby relieving the constrained generation in Pecos County. This solution may also address voltage stability constraints observed in other ERCOT studies, specifically the Dynamic Stability Assessment of High Penetration of Renewable Generation in the ERCOT Grid.[5]

Overall, ERCOT identified notable potential grid improvements including: a new 345-kV line from near the Panhandle region towards the Dallas-Fort Worth area; new 345-kV import paths in the northwest portion of the Dallas-Fort Worth area; a new Long Draw-Dermott 345-kV line; and a new 345-kV path from West Texas to San Antonio.

A list of upgrades and additions identified for Current Trends scenario are available in Figure 13 and Table 4 below. All these projects are conceptual in nature. Routing feasibility and other considerations were not considered in this assessment as the purpose of the analysis was to inform stakeholders of potential transmission solutions to address congestion seen in the study. More detailed analysis would be required to design necessary transmission additions and upgrades.

[4] http //www ercot com/content/wcm/key documents lists/76336/13 ERCOT Lubbock Load Integration Study.pdf

[5] http //www ercot com/content/wcm/lists/144927/Dynamic Stability Assessment of High Penertration of Renewable Generatio....pdf

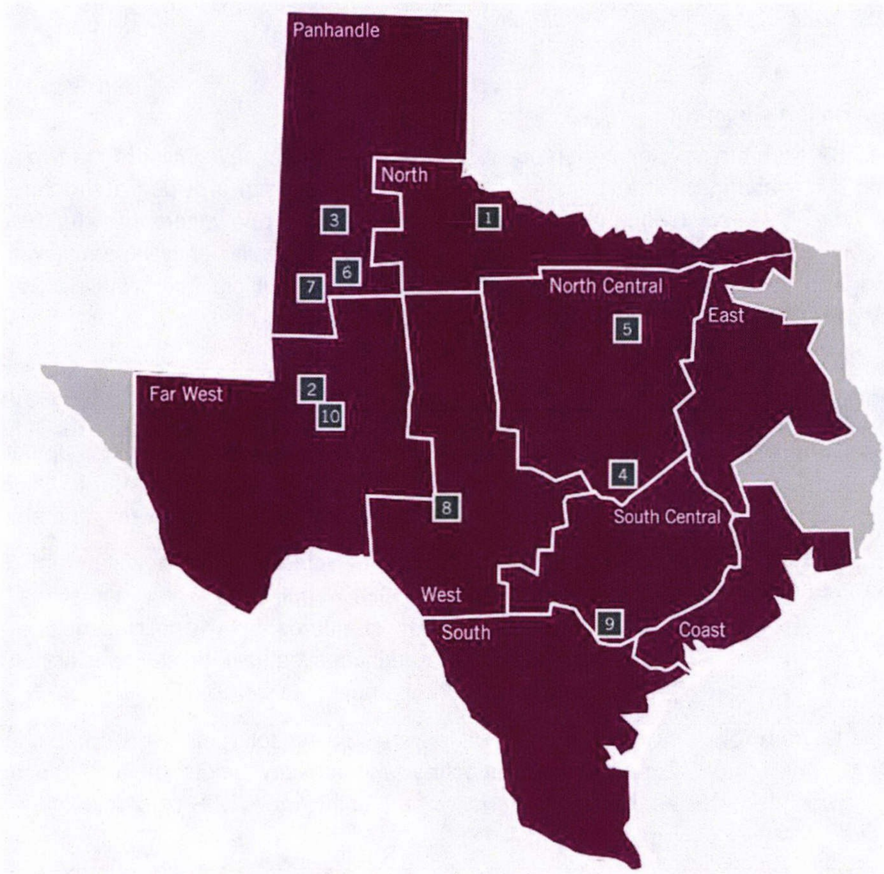


Figure 13: Transmission Upgrades and Additions

Table 4: Transmission Upgrades and Additions

Index	Projects	In service date
1	Oklaunion to Jacksboro new 345-kV line	2028
2	Odessa to Bearkat new 345-kV line	2028
3	Lubbock Loop (North to New Oliver new 345-kV line and Long Draw to Grassland 345-kV line upgrade)	2028
4	Northwest Austin Metro new 345-kV line and 345/138-kV transformer	2028
5	Northwest Dallas-Fort Worth new 345-kV line	2028
6	Faraday to Morgan Creek new 345-kV line	2028
7	Long Draw to Dermott new 345-kV line	2028
8	West Texas to San Antonio new 345-kV line	2028
9	Bergheim 345/138-kV transformer upgrade	2028
10	Odessa to Moss new 345-kV line	2033

Appendix

Appendix I: LTSA Process

LTSA Scenario Development

The 2018 LTSA scenario development process followed a methodology similar to the two prior LTSA studies with a few changes. The scenario-based planning approach provided a structured way for participants/stakeholders to identify the most critical trends, drivers, and uncertainties for the upcoming ten- to fifteen-year period. Scenario-based planning considered sufficiently different, yet plausible futures and was used to evaluate transmission plans across multiple future states. Some of the noteworthy drivers considered in the LTSA can be seen in Table I.1 below.

Table I. 1: Key Drivers Considered in the 2018 LTSA

Drivers	Brief description
Economic Conditions	The US and Texas economy, regional and state-wide population, oil & gas, and industrial growth, LNG export terminals, urban/suburban shifts, financial market conditions, and business environment
Environmental Regulations and Energy Policies	Environmental regulations including air emissions standards (e.g., ozone, MATS, CSAPR), GHG regulations, water regulations (e.g., 316b), and nuclear safety standards; energy policies include renewable standards and incentives (incl. taxes/financing), mandated fuel mix, solar mandate, and nuclear relicensing.
Alternative Generation Resources	Capital cost trends for renewables (solar and the wind), technological improvements affecting wind capacity factors, caps on annual capacity additions, storage costs, other DG costs, and financing methods.
Gas and Oil Prices	Gas prices are a function of total gas production, well productivity, LNG exports, industrial gas demand growth, and oil prices. Oil prices are dependent on global supply and demand balance, the spread of horizontal drilling technologies. Oil and gas prices will affect drilling locations within Texas.
Government Regulations/Policy/Mandates	New policies around resource adequacy, transmission buildout, interconnections to neighboring regions and cost recovery
Technology	Improvements in technologies resulting in more efficient turbines, or higher capacity factor intermittent resources
End-Use/New Markets	End-use technologies, efficiency standards, and incentives, demand response, changes in consumer choices, DG growth, increase interest in microgrids
Weather and Water Conditions	May affect load growth, environmental regulations, and policies, technology mix, average summer temperatures, the frequency of extreme weather events, water costs

ERCOT hosted scenario development workshops during the May and the June RPG meetings in 2017. A diverse group of stakeholders attended these workshops. These participants included but were not limited to representatives from segments such as Transmission, Conventional Generation, Renewable Generation, independent consultants, and interested citizens.

While the scenario-development process was similar to that used in 2014 and 2016 LTSA, ERCOT made several improvements prompted by stakeholder feedback on the lack of diversity in scenarios identified in prior year LTSA's. Unlike previous LTSA studies which identified 8-10 different scenarios, the objective of these workshops was to determine a smaller set of scenarios that had sufficiently diverse assumptions and warranted more in-depth analysis.

In the first scenario development workshop, ERCOT invited stakeholders to take an online survey. These surveys were designed to provide workshop participants an opportunity to express their views on drivers, scenarios, and critical assumptions. Stakeholders also identified some key sensitivities that could be considered to deepen understanding from each scenario. A summary of the survey results is included in Table I.2 and Figure I.1 and I.2 below.

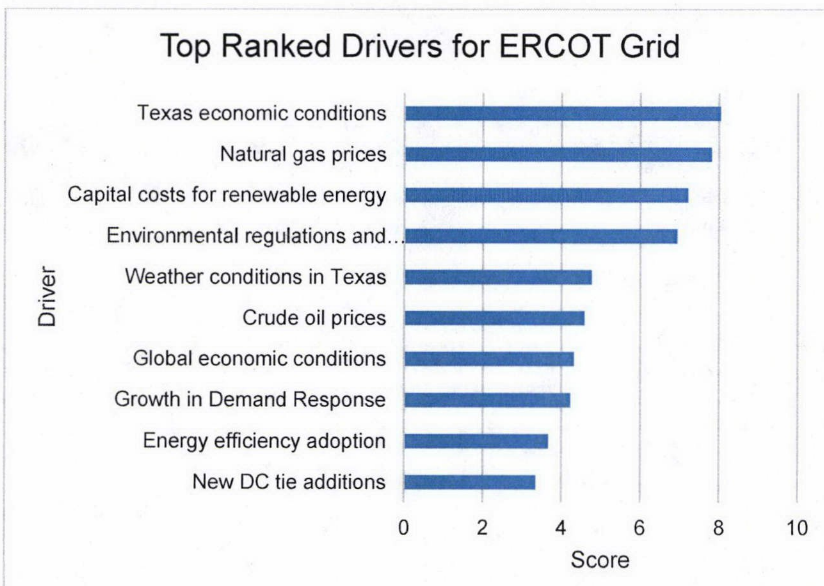


Figure I. 1: Summary of Survey Results: Key Drivers

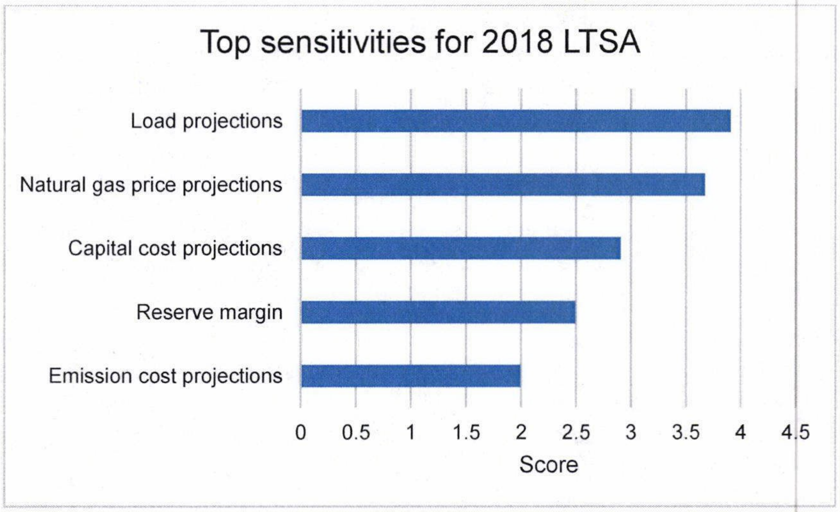


Figure I. 2: Summary of Survey Results: Top Sensitivities

Table I. 2: Summary of Survey Results: Key Assumptions

	Most likely	Most unlikely	Low	High	Notes
NG Price in $/mmBtu (by 2033)	2017 EIA AEO average of HOG and Ref Case (6.10)	2017 EIA AEO Reference Case (7.23)	2017 EIA AEO High Oil and Gas production Case (4.97)	2017 EIA AEO Reference Case (7.23)	Sub 4$ prices in 2033 for Current Trends
EE adoption	Business as usual (0.25%/year)	Aggressive (1.5%/year)	Business as usual (0.25%/year)	Aggressive (1.5%/year)	
Distributed PV in GW (by 2033)	Mid-case scenario :12.3	Low cost renewable energy : 21.1	High cost renewable energy: 2.5	Low cost renewable energy: 21.1	5 GW by 2033 for Current Trends
Carbon price (by 2033)	10$	30-40$	-	40$	
Environmental Regulations	None	-	-	CPP, CSAPR, Regional Haze, MATS	SO2 regulation for non-attainment for SO2 & carbon capture scenario

During the second workshop, stakeholders worked in teams to develop comprehensive descriptions of each scenario. Each group comprised a mix of members representing generation, transmission, ERCOT staff, and other stakeholders. Teams were encouraged to provide detailed future possibilities on various variables such as economic growth, environmental regulations/policy, alternative generation, oil and gas prices, transmission regulations/policy, resource adequacy, technological changes, end-use/new markets, and weather/water. The team summarized each scenario with a high-level narrative describing the future state and its implications for ERCOT. Table I.3 below summarizes the unique elements of each scenario.

Table I. 3: Scenarios Studied in the 2018 LTSA

Scenario	Description
Current Trends	The trajectory of what we know and is knowable today (e.g., LNG export terminals, Texas growth, low gas and oil prices). One significant shift in this year's Current Trends assumptions was around Environmental Regulations. Unlike previous LTSA, the 2018 LTSA assumed Regional Haze and CSAPR were not active.
High Economic Growth	Significant population and economic growth from all sectors of the economy (affecting load from residential, commercial and industrial). This scenario also included assumed sustained increase in oil and gas loads in West Texas along with growth in LNG terminals.
High Renewable Penetration	Favorable federal policies and reduction in overnight capital cost for Renewable technologies such as solar and wind result in high penetration of renewables in the ERCOT grid. This scenario also assumed higher levels of distributed solar adoption.
High Renewable Cost	A scenario designed to study the effects of the accelerated phase-out of renewable subsidies and a moderate increase in overnight capital cost.
Emerging Technology	A scenario designed to study the effect of rapid electrification of the transportation sector in Texas.

The final input assumptions used in creating 2018 LTSA study are documented in the following Table.

Table I. 4: 2018 LTSA Input Assumptions

	Base							Sensitivity		
	Demand				Generation					
	Growth rate	Energy (GWH) - Inclusive of Distributed PV	Peak (MW) - inclusive of Distributed PV	Distributed PV (GW)	NG price forecast ($/mmBtu) in 2033 nominal $	Renewables - Annual Capacity addition limitations	Renewable incentives	Sensitivity 1	Sensitivity 2	Sensitivity 3
Current Trends	1.40%	537,819	94,554	1.0	4.5	Wind: 3000 MW Solar: 1500 MW	PTC/ITC phase out as currently expected	AEO 2018 reference gas price (high gas exp)	CT with reserve margin 13.75%	Lubbock
High Renewable Penetration	1.40%	499,287	89,354	20.0	4.5	Same as CT	PTC/ITC do not expire	Increase the solar limit to 3000 MW + Lubbock (remove panhandle limit)	Based on Sensitivity one + county limitation	
High Economic Growth	2.20%	575,968	102,410	3.0	6.2	Same as CT	Same as CT			
High Renewable Costs ^	1.40%	537,380	94,174	1.0	4.5	Wind: 600 MW Solar: 300 MW	Same as CT			
Emerging Technology Scenario *	1.40%	614,043	102,492	1.0	4.5	Same as CT	Same as CT	Lower EV adoption scenarion (50% lower)		

* 3 million cars, 80 thousand short haul trucks/buses and 0.2 million long haul trucks
+ PTC: $0.023/kWh, PTC amount reduced by 40% and 60% for plants begin construction in 2018 and 2019. Applies to first 10 years of operation.
^ 30% import duties applied on Solar panels (applied as increase in overnight capital cost)

Load Forecasting

One key component to any long-term transmission plan is an appropriate forecast of the electric load. Changes in electricity consumption contribute to future transmission needs as do new generation technologies, generator obsolescence, economic, commercial, and policy factors. Transmission plans study the reliable movement of electricity from generation sources to consuming load locations; therefore, planners need to know which resources can provide electricity as well as how much electricity will be required and where. The uncertainty in many of these factors can be significant; as such, load forecasters often prepare several forecasts that reflect different possible futures and circumstances so transmission planners can study load, generation, and transmission needs for those various futures and conditions.

Two different forecasts were created for the years between 2019 and 2033 to support the scenarios included in this study. These forecasts used different values for a set of input variables that were consistent with the scenario-specific assumptions.

Forecast Development

The load forecasts combined econometric input and scenario-specific assumptions as input into forecast models to describe the hourly load in the region. Factors considered included certain economic measures (e.g., nonfarm payroll employment, housing stock, population, number of premises) and weather variables (e.g., heating and cooling degree days, temperature, cloud cover, dew point, and wind speed). Detailed documentation on ERCOT's Long-Term Load Forecast can be found on the Long-term load forecast page on the ERCOT website[6].

Load Modeling

ERCOT consists of eight distinct weather zones. Each of these weather zones represents a geographic region within which all areas have similar climatological trends and characteristics. The ERCOT forecast is the sum of all of the weather zone forecasts. A map of weather zones is shown in Figure I.3.

[6] http.//www ercot com/content/wcm/lists/114580/2017_Long-Term_Hourly_Peak_Demand_and_Energy_Forecast pdf

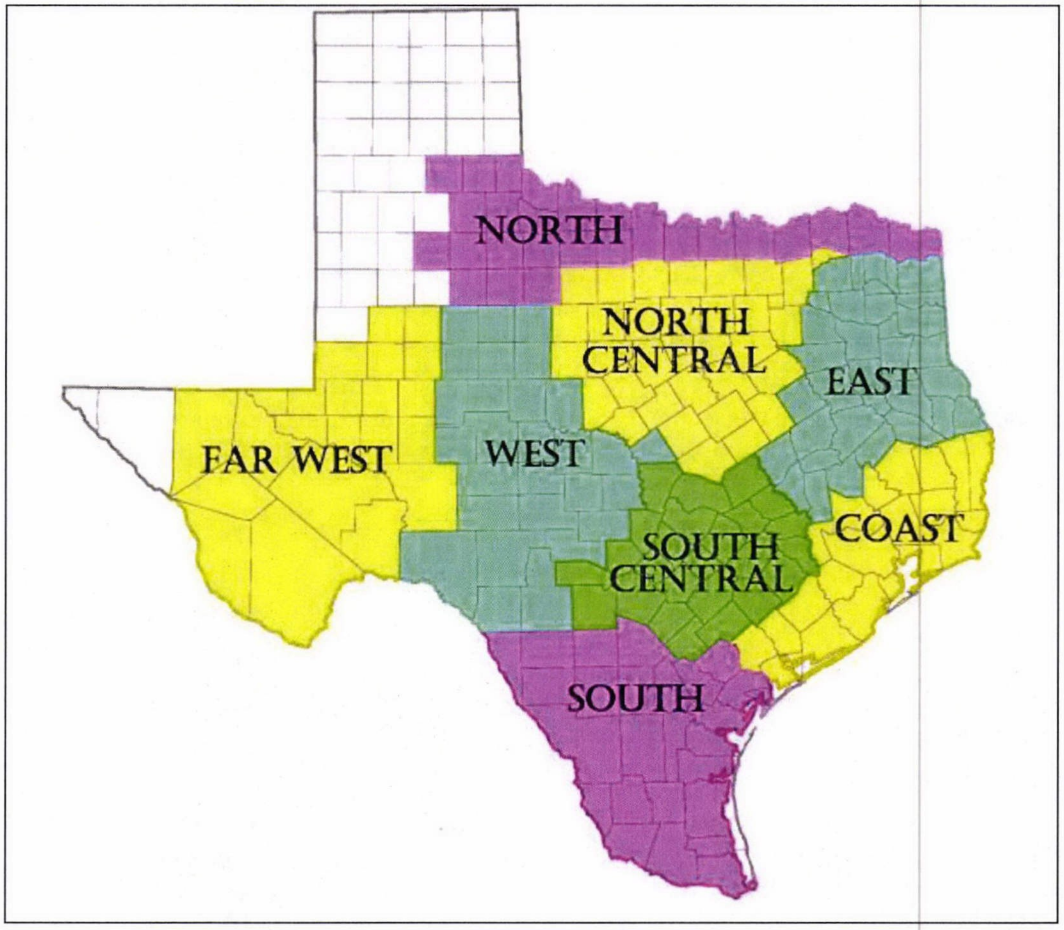


Figure I. 3: ERCOT Weather Zones

Model Forecasting

These scenario-specific forecasts used models that combine weather, economic data, and calendar variables to capture and project the long-term trends extracted from the historical load data. The models were developed using historical data from 2012 through the summer of 2017.

Premises were separated into three different customer classes for modeling purposes: residential, business, and industrial. The premise count models consider changes in population, housing stock, and non-farm employment. An autoregressive model (AR1) was used for all premise models.

Hourly Energy Models

The long-term trend in hourly energy was modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable, hourly energy and the following:

- Month,
- Season,

- Day Type (day of the week, holiday),

Weather Variables,

- Temperature,
- Temperature Squared,
- Temperature Cubed,
- Dew Point,
- Cloud Cover,
- Wind Speed,
- Cooling Degree Days (base 65),
- Heating Degree Days (base 65),
- Lag Cooling Degree Days (1,2, or 3 previous days),
- Lag Heating Degree Days (1,2, or 3 previous days), and
- Lag Temperature (1, 2, and 3, 24, 48, or 72 previous hours).

Interactions

- Hour and Day of Week,
- Hour and Temperature,
- Hour and Dew Point,
- Temperature and Dew Point, and,
- Hour and Temperature and Dew Point.
- Number of premises[7], and
- Non-Farm Employment/Housing Stock/Population

All of the variables listed above are used to identify the best candidates for inclusion in the forecast model and to provide details on the types of variables that were evaluated in the creation of the model. Not every variable listed above was included in each model. Unique models were created for each weather zone to account for the different load characteristics for each area.

Premise Forecast

Another key input is the forecast for the number of premises in each customer class. Premise forecasts are developed using historical premise count data and various economic variables, such as non-farm employment, housing stock, and population. ERCOT extracted the historical premise data from its internal settlement databases. Since May of 2010, there has been a reasonably close agreement between actual non-farm employment in Texas and Moody's base economic forecast. Given this trend, ERCOT used the Moody's base economic forecast of non-farm employment in these forecasts. Separate premise forecast models were developed for each weather zone. The premises were separated into three different groups for modeling purposes namely, Residential (including street lighting), Business or small commercial, and Industrial (premises that are required by protocol to have an interval data recorder meter).

[7] *Used in Coast, East, North Central, South, and South Central weather zones*

- Residential Premise Forecast: Residential premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (residential premises) and the following:
  - Housing Stock and
  - Population.
- Business Premise Forecast: Business premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (business premises) and the following:
  - Housing Stock,
  - Population, and
- Non-Farm employment.
- Industrial Premise Forecast: Industrial premise counts were modeled by estimating a relationship for each of the eight ERCOT weather zones between the dependent variable (industrial premises), and the
  - Housing Stock,
  - Population, and
  - Non-Farm employment.

Premise Model Issues

During the review process for the previously mentioned premise models, two problems were identified. The first problem, which was noted in the Far West and West weather zones, was that during the historical timeframe used to create the models, there was a significant increase in the number of premises in the middle of 2014. This increase was due to an entity opting into ERCOT's competitive market and due to an expansion of ERCOT's service territory.

The second problem, which affected the North weather zone, was that premise counts were relatively flat, which made it difficult to be modeled using economic data.

As a result of these two problems, premise forecast models were not appropriate for the Far West, West, and North weather zones. For these three weather zones, ERCOT used economic variables as the key driver in the forecasted growth of demand and energy.

Weather Forecast

The 2018 LTSA generation expansion and transmission economic analyses used an 8760-hour load forecast. This base load forecast before adjustments for four of the five scenarios was based on the 2009 weather year. These scenarios include the Current Trends, High Renewable Penetration, High Renewable Cost and Emerging Technology. The High Economic Growth scenario used 2011 weather year to represent the higher than normal load forecast. Scenario specific load adjustments were applied based on the input assumptions. These adjustments are described in detail in the next section.

Load Forecast Study Adjustments

ERCOT's load forecasts include losses, which were removed before adjusting load because the software packages used for both reliability and economic analyses account for losses separately from the load. Furthermore, scenario-specific load adjustments were also applied.

For instance, distributed solar was assumed to be concentrated in the major load centers and was modeled based on residential (distributed solar) generation profiles. Distributed solar of 1,000 MW was considered in Current Trends, High Renewable Cost and Emerging Technology scenarios. A

3,000 MW distributed solar was assumed to be in the High Economic Growth scenario. The highest amount of distributed solar of 20,000 MW was included in the High Renewable Penetration scenario.

In recent years, west Texas has seen tremendous load growth. This load growth can be attributed to oil and gas related load growth. This current pace of oil and gas related load development in west Texas was assumed to continue through 2033 in the High Economic Growth scenario resulting in higher Far West weather zone.

Furthermore, the 2018 LTSA load forecasts for the High Renewable Penetration scenario assumed modest growth in Energy Efficiency related demand reduction of 3%. Three hundred MW of Energy Efficiency was considered as a starting point based on publicly filed reports by the TSPs.

EV charging patterns for cars, short-haul trucks and buses and long-haul trucks were used to model the effect of EV adoption. Details for EV charging patterns can be found in Chapter 3 of this report.

Also, the load forecasts did not include self-served load. The self-served loads were left unchanged from the reliability and economic base cases while the load forecasts (net of losses) were distributed to all other loads in the cases on a by-weather-zone basis.

Resource Expansion Analysis

The resource expansion analysis is used to estimate the types and amount of new generation resources to be added, and the existing generation resources to be retired for every scenario. To provide a reference point for the selection of other future scenarios, scenario-development workshop participants created a Current Trends scenario as the first scenario. The primary input assumptions for all scenarios were the capital cost, new technology types, incentives, and wind and solar locations and profiles. The long-term generation expansion concept is depicted in Figure I.4.

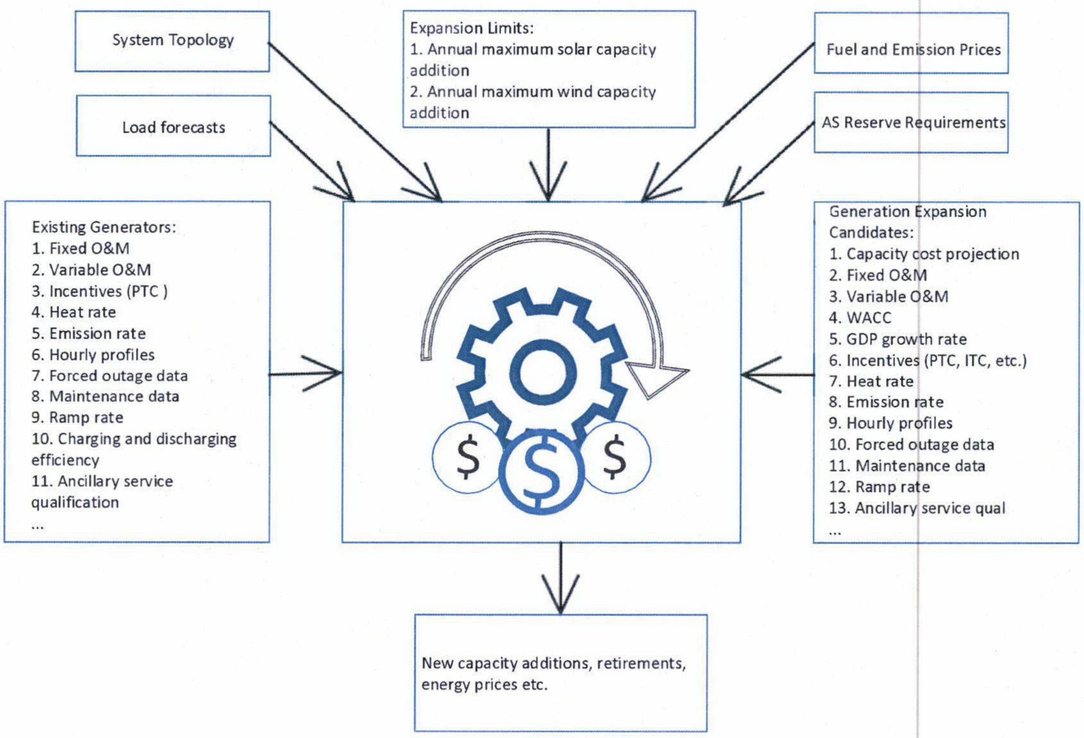


Figure I. 4: Long-term Generation Expansion Concept

Trends in capital costs for new expansion technologies generally increased at an assumed GDP growth rate in this analysis except for the wind, utility-scale solar and battery storage technologies which were forecasted to decline rapidly through the early part of the study period. Commodity prices for gas were set as the EIA AEO 2018 High Oil and Gas Resource and Technology Case.

The technologies included for generation expansion in this LTSA were current and advanced gas-fired combined cycles and combustion turbines, solar, geothermal, compressed air energy storage (CAES), Li-ion battery storage, biomass, coal, coal with carbon capture and sequestration (CCS), Integrated Gasification Combined Cycle (IGCC), IGCC with CCS, and nuclear. The solar technology evaluated in the generation expansion process was utility-scale solar dual axis tracking.

Additionally, the 2017 extension[8] of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) was included in four of the five scenarios for renewable generation. These scenarios include the Current Trends scenario, the High Economic Growth scenario, the High Renewable Cost scenario and the Emerging Technology scenario. For the High Renewable Penetration scenario, the PTC and ITC were not assumed to be phased down or expired throughout the study period.

In 2015, ERCOT procured hourly wind generation patterns based on actual weather data for the previous 17 years (1997-2013). These wind patterns include hourly wind output patterns for 130 hypothetical future wind generation units and were developed using power generation curves consistent with the most recent wind turbine technologies. The 130 profiles were distributed throughout Texas. Each profile is representative of the historical wind output in a specific county if there is existing wind farm in the county. These wind profiles were incorporated in all scenarios.

In 2016, ERCOT procured new hourly solar generation patterns based on actual weather data for the previous 19 years. These patterns contained profiles representative of the west and panhandle Texas counties for two different types of solar technologies: single-axis and dual-axis tracking. Four distributed solar profiles have been developed for four urban load centers including Dallas Fort Worth, Austin, Houston, and San Antonio. ERCOT selected the dual-axis tracking and residential profiles for inclusion in this LTSA.

Additionally, AURORA, an electricity market modeling, forecasting, and analysis tool, was used to determine the timing, approximate location of wind and solar resources, and capacity of new entrants (generating units) likely to participate in the competitive electric energy market along with units that may be economically retired. The objective of some conventional generation expansion model is to minimize total system cost in optimization window. Since generation resource investment is a big and long-term investment, the generation expansion optimization window has to be across multiple years. To make the optimization problem manageable by current computer technology, the size of the optimization problem has to be reduced significantly. Therefore, hourly chronological demand is transformed into slices of the load duration curve based on load levels. Since solar and wind are modeled as hourly chronological profiles and treated as negative load, their generation is grouped and averaged within every load block. You would expect load in some hours after sunset could be similar to load in some hours when the sun is shining, so some night and day hours could be grouped in the same block, averaging solar generation will incorrectly make solar generation available during night hours. The software used makes capacity addition and retirement decisions based on individual generation economics. This approach can be easily segmented and parallelized, so it can directly consider hourly chronology of load, wind and solar generation in the optimization problem.

A significant aspect of the expansion decision process is capital cost recovery. Using the specified capital costs, recovery period, inflation rate, and cost of capital, the model calculated a repayment that was paid in equal installments over the capital recovery period. The inflation rate ensures that units that were added in the future have their capital costs appropriately adjusted for inflation providing consistency with the other specified costs. A summary of this analysis can be found in Appendix II below.

The amount of renewable generation included in the scenarios is partially a result of the use of an hourly system dispatch model to develop the resource expansion plan. This type of model does not

[8] https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc, https://www.energy.gov/savings/business-energy-investment-tax-credit-itc

simulate intra-hour balancing reserve deployment and the need for commitment of additional resources to limit the impact of variable generation forecasting error consistent with increased levels of renewable generation integration. Separate analysis needs to be conducted to determine the need for additional system flexibility to integrate levels of renewable resources seen in this analysis.

Transmission Expansion Analysis

Transmission expansion analysis in the LTSA involves evaluating the potential needs for the ERCOT grid under different load and generation assumptions as developed during the load forecasting and generation expansion planning stages. Transmission expansion analysis was conducted for the Current Trends scenario. The Transmission expansion analysis was focused on analyzing congestion on ERCOT's 345-kV and 138-kV network and identifying long-range transmission upgrades and additions to its 345-kV network. These studies included analysis such as 8760-hour production cost model simulation, contingency analysis, and transfer analysis.

ERCOT used the UPLAN NPM model to perform transmission expansion analysis. ERCOT used the final case for the year 2023 from the 2017 RTP reliability and economic analysis as a starting point for the Current Trends scenario. This case was first updated to incorporate the status change to the existing and future generators, which occurred before the start of this study, and the status change to the near-term transmission projects, as well.

For each scenario and each study year, the case was then modified with the generation fleet changes and load adjustments, which resulted from the inputs from the scenario development. ERCOT used the resource profile, including generation retirement, generation addition, and the profile for demand response, as developed in the generation expansion planning process, to model the generation build, for each scenario and each study year. The location of the new generation resources was determined based on the limitations of the technology; certain technologies such as combustion turbines are more flexible and can be built in many areas across the state, whereas the availability of the natural resources limits solar and wind resource locations. Figure I.5 shows the results of generation siting in the Current Trends scenarios considered for transmission expansion analysis. The resources were modeled in the cases at the appropriate buses as outlined in the guidelines from the generation siting methodology. Similarly, generating units were retired consistent with the resource expansion results.

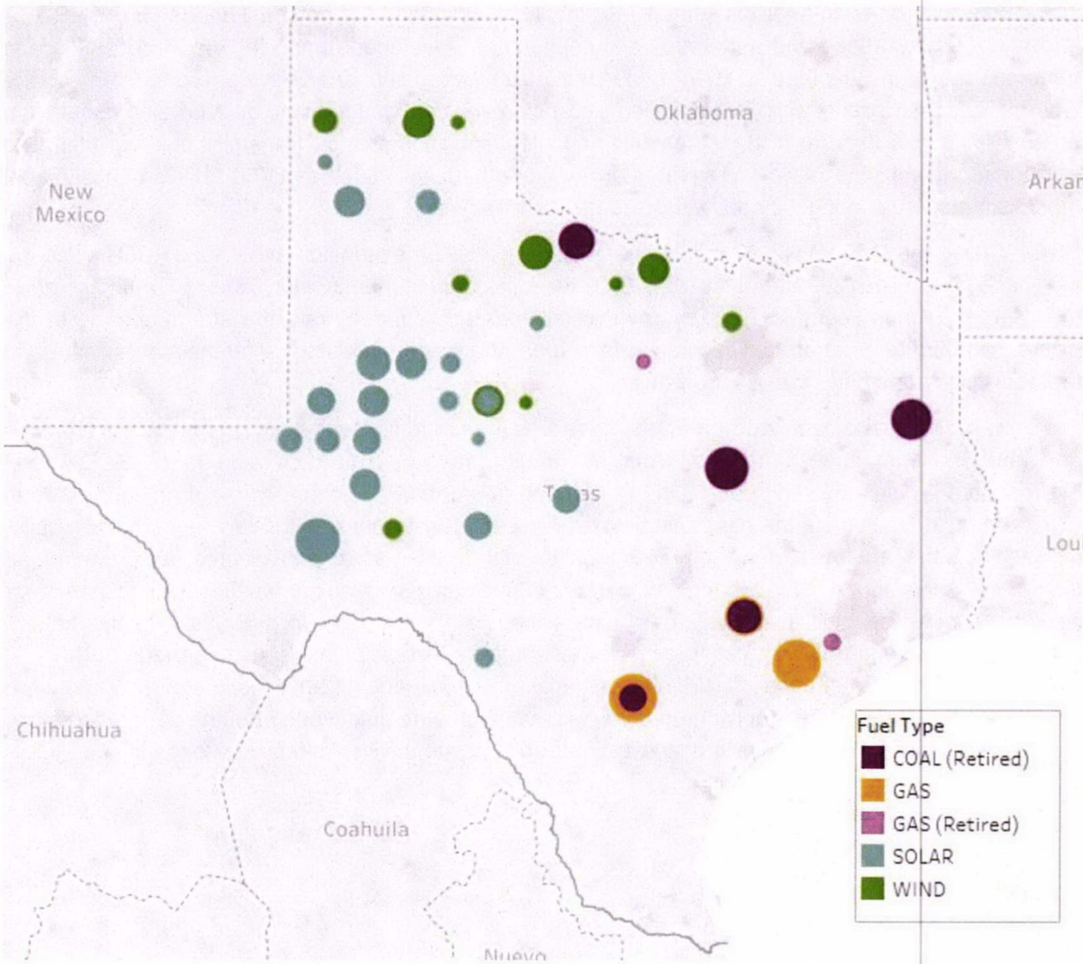


Figure I. 5: Generation Additions and Retirements in 2033 Current Trends Scenario

ERCOT used the 50th-percentile hourly load forecast, in addition to the self-served load, to model the system demand. Effects of distributed solar and energy efficiency were assumed to be included in the load forecasts used in the transmission expansion analysis.

ERCOT analyzed each of the scenario-appropriate base cases created for 2028 and 2033 to determine the potential transmission needs of the system. ERCOT studied NERC TPL-001-4 Planning Events P0, P1, and P7, which included the loss of a generator, a transmission circuit, transformer, or a shunt device. ERCOT's P7 planning events also included the loss of double circuit lines that share towers for more than half a mile. In addition to the above contingencies, ERCOT included generator maintenance outages in this evaluation.

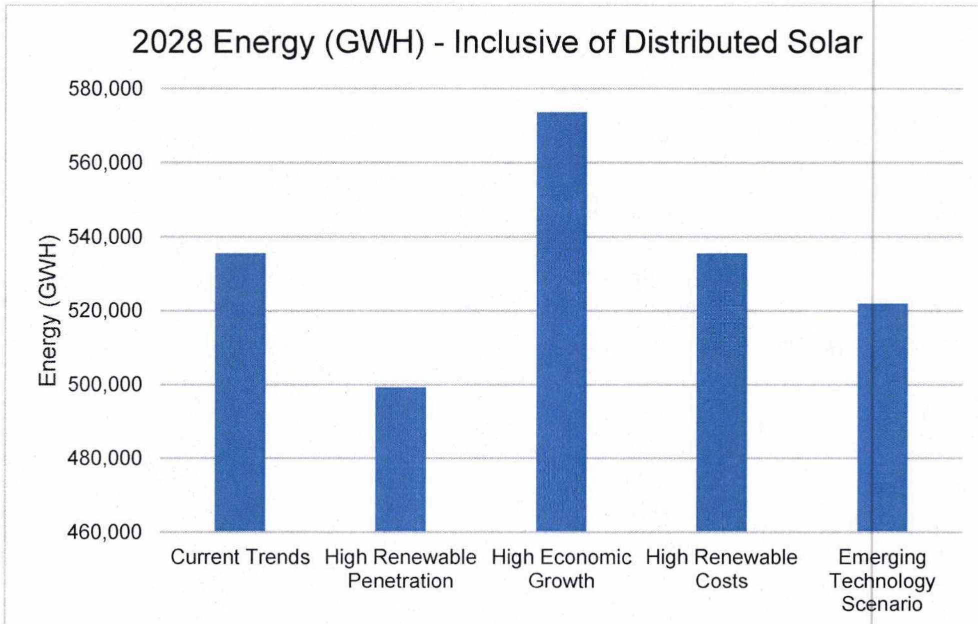
ERCOT evaluated the contingencies at all voltage levels, but mainly addressed violations and congestion on the network connected at 100-kV and above, as the needs to resolve violations and congestion on the 69-kV network were assumed to be addressed through the RTP process and/or other near-term planning processes. To reveal the potential violations and congestion on the 345-kV network, ERCOT added transmission upgrades due to identified local needs to facilitate generation addition and demand growth in the corresponding start cases and did not monitor the 69-kV transmission elements.

Given that all studied scenarios included the addition of large amounts of renewable generation to the far west and northern regions of the ERCOT grid, ERCOT defined transmission interfaces according to the location of the renewable generation and performed appropriate analyses to determine the export limits from the renewable generation for each scenario and each study year.

ERCOT developed long-range transmission solutions to address reliability and congestion needs of the system across the three scenarios. Cost estimates for potential transmission projects used in this study do not reflect routing considerations, such as geographic obstacles, physical constraints, or public preferences. Detailed routing considerations can lead to project cost increases. A summary of this analysis can be found in Appendix II below.

Appendix II: Scenario results summary

Load Forecasts



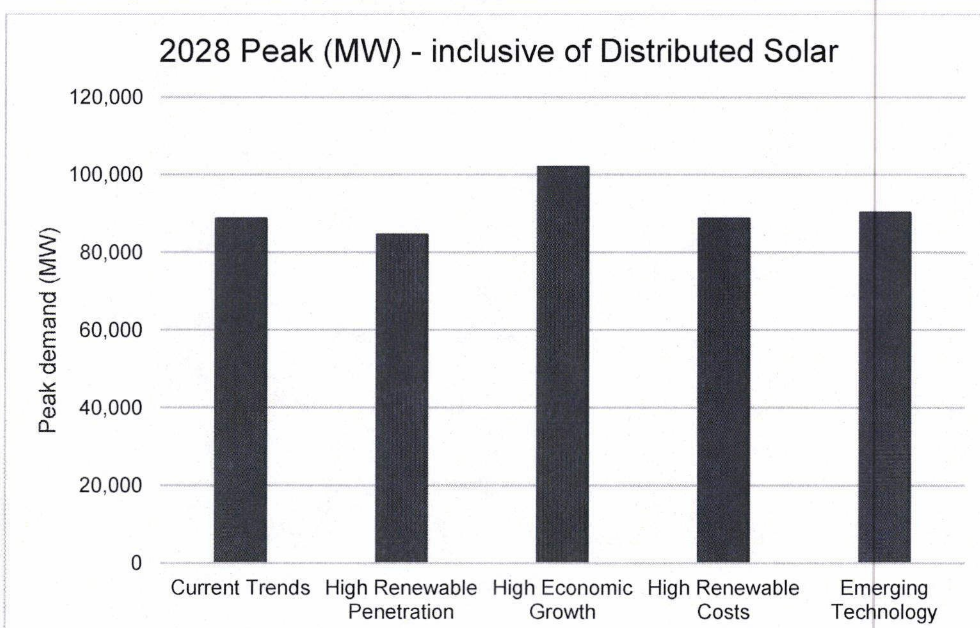
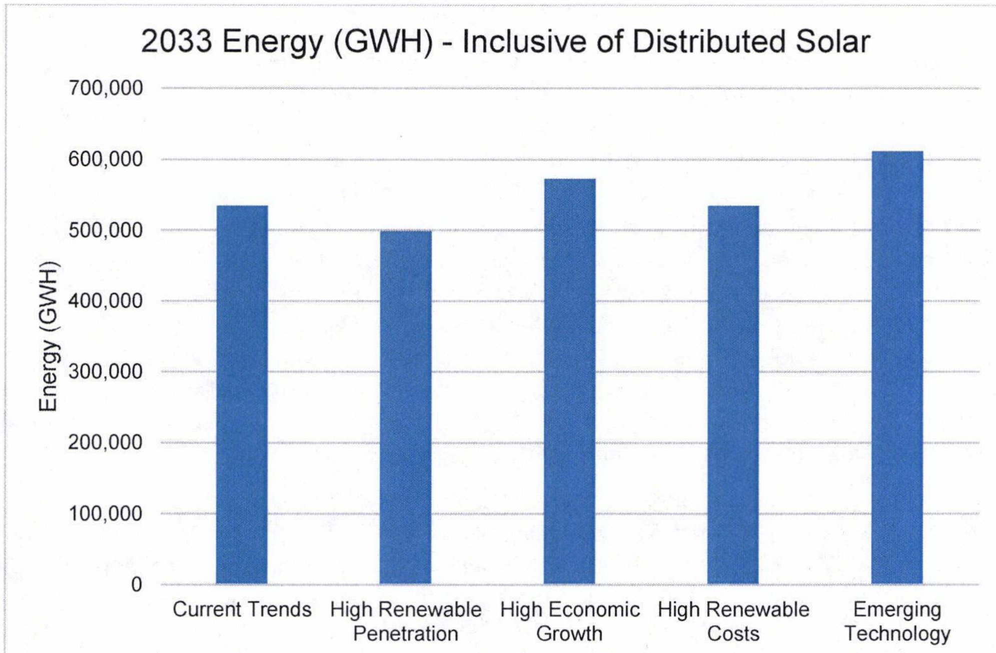


Figure I. 6: Energy and Peak for 2028 across the Five Scenarios



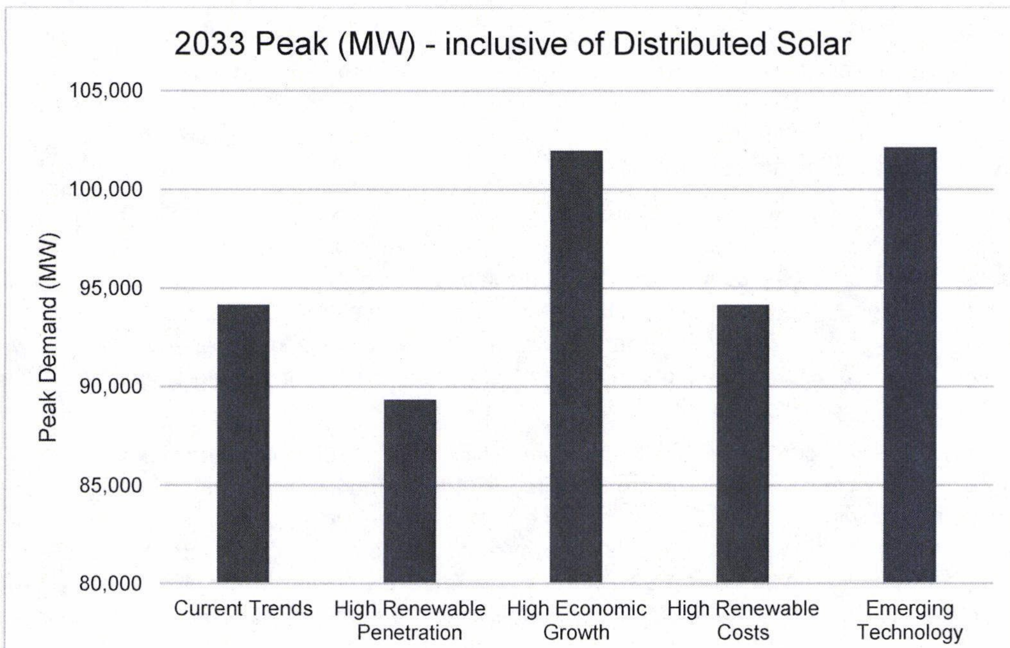


Figure I. 7: Energy and Peak for 2033 across the Five Scenarios

Current Trends

This scenario is designed to simulate current market conditions extended 15 years into the future. Since the PUCT approved the Lubbock Power & Light integration in to ERCOT in March 2018, the Current Trends scenario included Lubbock Power & Light. A new 2,000 MW DC tie was also included in this scenario. The DC tie was modeled to export renewable generation during high renewable generation periods and import energy during ERCOT peak load hours which was based on a 2015 analysis[9]. Another improvement in the study process was considering transmission availability for new wind and solar resources. The locations of planned wind and solar generation resources in the generation interconnection queue were studied to identify a list of potential counties already represented in the queue. New wind and solar resources in the generation expansion analysis could only be added in potential counties. This limitation was intended to take transmission availability into consideration because proposed projects are usually close to available transmission. The transmission availability consideration was found to limit solar resources more than wind because many wind projects were proposed at high quality wind resource locations in the queue.

The generation expansion model added 2,800 MW combined cycle capacity, 12,600 MW utility scale solar capacity and 6,200 MW wind. The total retirements were 3,700 MW. Compared to the Current Trends scenario of 2016 LTSA, potential scarcity conditions during evening time was about the same due to the large amounts of wind and solar resources that were added to the system. More gas generation was added in 2018 LTSA because of the lower gas price projection. More wind was added in the 2018 LTSA because the new DC tie could export some of the wind generation. A summary of the generation expansion results for the Current Trends scenario is shown in Table I.5.

The following two sensitivity cases were evaluated for Current Trends scenario: (1) higher gas prices as in 2018 AEO reference case were assumed in this sensitivity to investigate how gas prices drive capacity expansion; (2) the transmission availability consideration for wind and solar resources was removed to study the impacts of this limit.

In Sensitivity (1), compared to the Current Trends base scenario, the model added 1,750 MW less gas capacity, 900 MW less solar capacity and 4,300 MW more wind capacity as shown in Figure I.8. The high gas price increased the operational cost of gas capacity so less gas capacity was added. On the other side, the higher gas price made coal generation more competitive so there were 3,300 MW less retirements as shown in Figure I.9. The high gas price also increased the energy price so wind generators, which generally have higher capacity factors than solar, became more competitive. As a result, more wind capacity was added.

In Sensitivity (2), the model added 3,750 MW more gas capacity, 2,100 MW more solar and 3,200 MW less wind as shown in Figure I.8. The model retired 3,740 MW more capacity as shown in Figure I.9. The difference between Current Trends base scenario and Sensitivity (2) revealed the transmission availability consideration was limiting solar capacity addition and encouraged wind capacity addition. More capacity was retired because the existing generators received more competition from new solar resources in Sensitivity (2). More gas and solar capacity was added to replace the retired capacity.

[9] http //www ercot com/content/wcm/key_documents_lists/113048/3d_45624_Exhibit_EW-2_SCT_Economic_Evaluation_Report_02_23_16 pdf

Table I. 4: Generation Expansion Results for Current Trends Scenario

Description	Units	2,019	2,023	2,028	2,033
CC Adds	MW	1,000	1,000	-	750
CT Adds	MW	-	-	-	
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Solar Adds	MW	1,500	6,000	5,100	100
Wind Adds	MW	3,000	3,300	100	-
Annual Capacity Additions	MW	5,500	10,300	5,200	850
Cumulative Capacity Additions	MW	5,500	15,800	21,000	21,850
Economic Retirements	MW	-	3,705	-	-
Cumulative Economic Retirements	MW	-	3,705	3,705	3,705
Reserve Margin	%	12	11	8	3
Coincident Peak	MW	78,203	83,544	89,157	94,554
Annual Energy	GWhs	423,043	460,622	501,443	537,819
Average LMP	$/MWh	33	38	51	71
Natural Gas Price	$/mmbtu	3	3	4	4
Average Market Heat Rate	MMbtu/MWh	10	11	12	16
Natural Gas Generation	%	60	59	56	59
Coal Generation	%	5	3	5	5
Wind Generation	%	22	21	20	18
Solar Generation	%	3	7	10	9
Scarcity Hours	HRS	-	2	7	21
Unserved Energy	GWhs	-	1	12	35

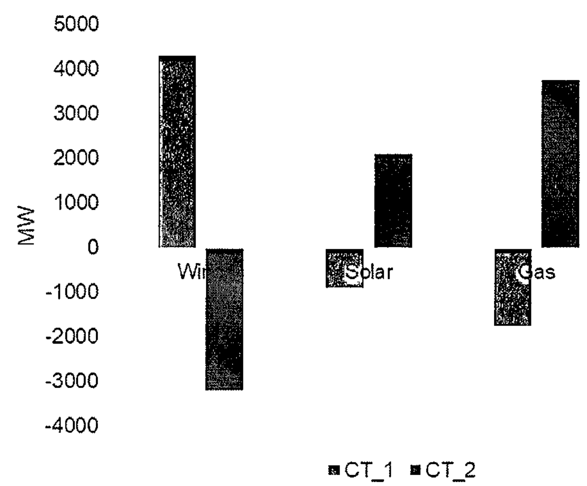


Figure I. 8: Capacity Addition Difference between Current Trends Scenario and Its Sensitivity Cases

Figure I. 9: Capacity Retirement Difference between Current Trends Scenario and Its Sensitivity Cases

Transmission Expansion Analysis Results

As described in Appendix I, ERCOT used the UPLAN NPM model to perform transmission expansion analysis. Any recently approved RPG projects, projects recommended in the 2018 Regional Transmission Plan study and local 138-kV upgrades and additions were included in the start case. Figures I.10 and I.11 show a map of Texas with the top congested elements connected at levels 100-kV and higher for study years 2028 and 2033. The size of the bubbles on the chart indicate the amount of annual congestion rent for the study year. The location of the bubbles on this chart show the location of the constrained element. Several large, inter-regional transmission upgrades were evaluated using ERCOT's economic criteria. Any transmission upgrades or additions that provided enough production cost savings while addressing reliability and economic needs of the system were included in the final LTSA transmission plan. Figure I.12 and I.13 show the remaining congestion on the system. While much of the original congestion across the system has been addressed with the solutions identified in Table I.6 below, the system continued to see a need for further evaluations in the Dallas-Fort Worth and Houston areas.

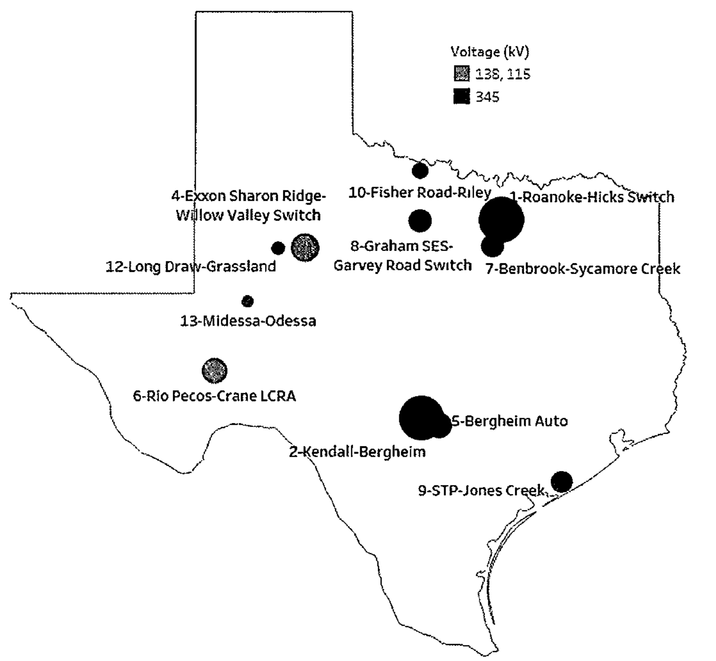


Figure I. 10: Top Initial Congested Elements in 2028 for Current Trends Scenario

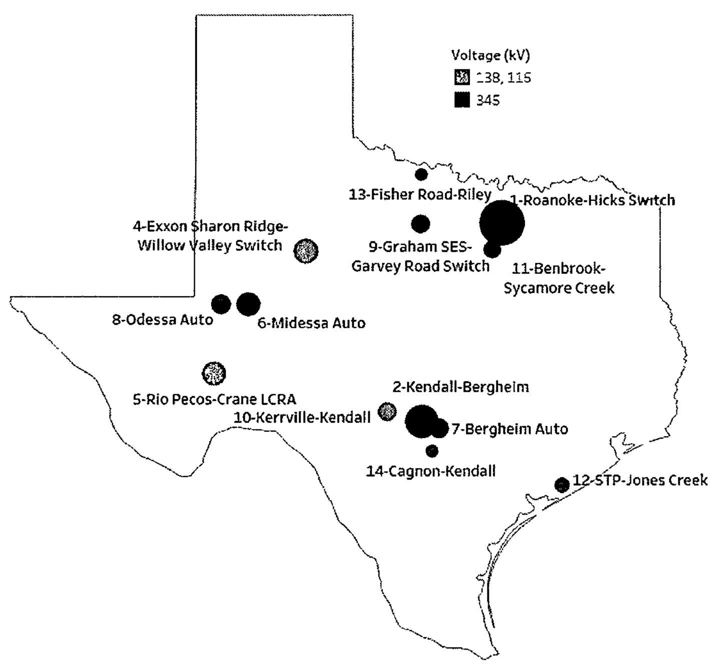


Figure I. 11: Top Initial Congested Elements in 2033 for Current Trends Scenario

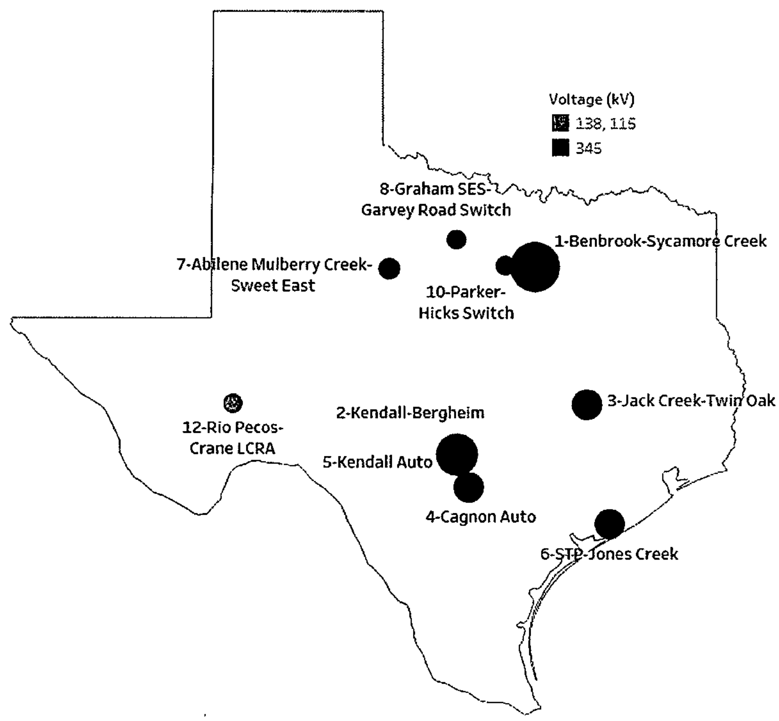


Figure I. 12: Top Final Congested Elements in 2028 for Current Trends Scenario

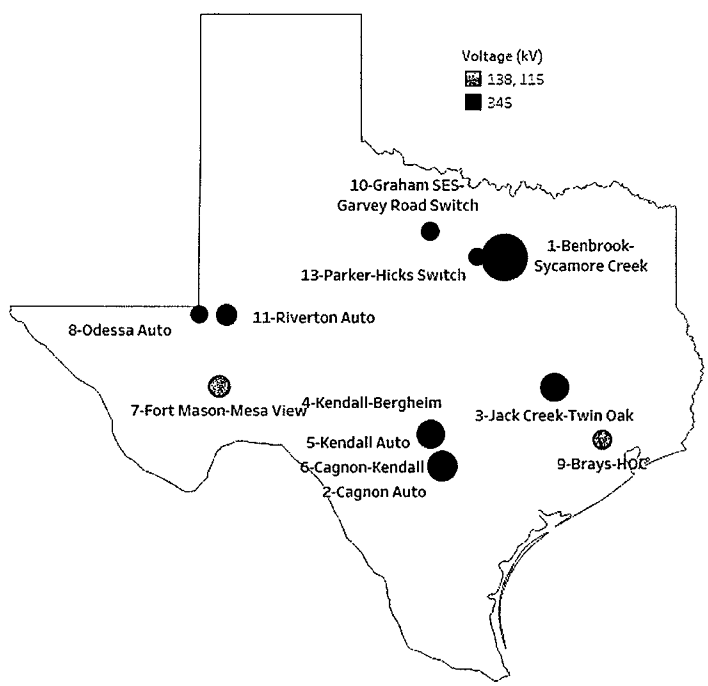


Figure I. 13: Top Final Congested Elements in 2033 for Current Trends Scenario

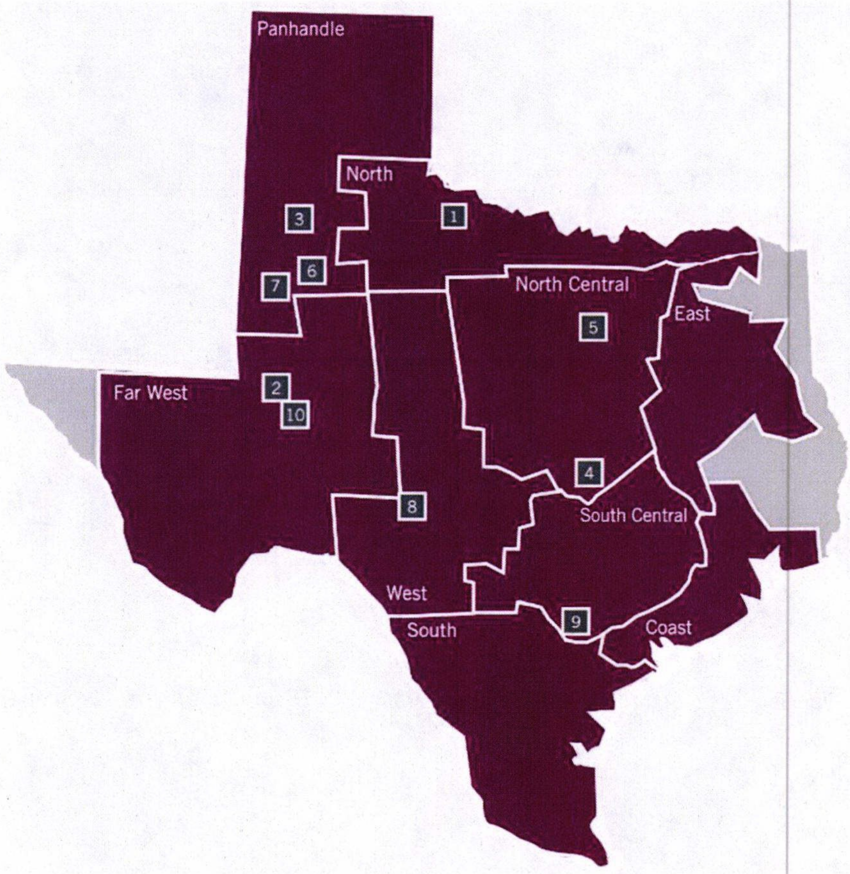


Figure I. 14: Transmission Upgrades and Additions

Table I. 5: Transmission Upgrades and Additions

Index	Projects	In service date
1	Oklaunion to Jacksboro new 345-kV line	2028
2	Odessa to Bearkat new 345-kV line	2028
3	Lubbock Loop (North to New Oliver new 345-kV line and Long Draw to Grassland 345-kV line upgrade)	2028
4	Northwest Austin Metro new 345-kV line and 345/138-kV transformer	2028
5	Northwest Dallas-Fort Worth new 345-kV line	2028
6	Faraday to Morgan Creek new 345-kV line	2028
7	Long Draw to Dermott new 345-kV line	2028
8	West Texas to San Antonio new 345-kV line	2028
9	Bergheim 345/138-kV transformer upgrade	2028
10	Odessa to Moss new 345-kV line	2033

High Economic Growth

This scenario was designed to simulate high population and economic growth from all sectors of the economy. It also assumed sustained increase in oil and gas loads in West Texas along with growth in LNG terminals and the domestic gas price was projected to be higher than the Current Trends scenario since the LNG would export some of the gas and there should be high demand for gas due to economic boom.

The generation expansion model added 2,400 MW more solar capacity, 1,900 MW less wind capacity and didn't retire any existing units. The net capacity addition was 4,200 MW more than the Current Trends scenario though the peak load in 2033 was 7,900 MW higher than the Current Trends scenario. Therefore, there were more potential scarcity hours than the Current Trends scenario and coal generation supplied around 19% of demand while it only served less than 5% of demand in the Current Trends scenario. The generation expansion results of the High Economic Growth scenario are summarized in Table I.7.

Table I. 6: Generation Expansion Results for High Economic Growth Scenario

Description	Units	2019	2023	2028	2033
CC Adds	MW	-		750	2,000
CT Adds	MW	-	-	-	
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Recip Adds	MW	-	-	-	-
Storage Adds	MW	-	-	20	-
Solar Adds	MW	1,500	6,000	6,900	700
Wind Adds	MW	2,100	2,000	400	-
Annual Capacity Additions	MW	3,600	8,000	8,070	2,700
Cumulative Capacity Additions	MW	3,600	11,600	19,670	22,370
Economic Retirements	MW	-	-	-	-
Cumulative Economic Retirements	MW	-	-	-	-
Reserve Margin	%	5.0	6.3	5.8	0.5
Coincident Peak	MW	82,534	88,636	94,912	102,410
Annual Energy	GWhs	440,268	481,891	530,649	575,968
Average LMP	$/MWh	57.68	37.25	59.44	125.16
Natural Gas Price	$/mmbtu	3.55	4.42	5.42	6.15
Average Market Heat Rate	MMbtu/MWh	16.25	8.43	10.97	20.35
Natural Gas Generation	%	49.4	44.0	42.8	46.9
Coal Generation	%	16.9	20.0	19.6	18.4
Wind Generation	%	21.2	20.8	19.3	17.8
Solar Generation	%	2.4	6.4	9.9	9.5
Scarcity Hours	HRS	27.0	-	13.0	69.0
Unserved Energy	GWhs	35.1	-	27.0	164.6

High Renewable Penetration

This scenario was designed to include a lot more renewable generation by assuming 20,000 MW of distributed solar capacity in the system based on stakeholder inputs. The PTC and ITC were not assumed to be phased down or expired throughout the study period.

The generation expansion model added 2,000 MW combined cycle capacity, 11,900 MW utility scale solar capacity and 8,600 MW utility scale wind capacity. Total retirements were 5,600 MW. Compared to the Current Trends scenario, the model added 750 MW less combined cycle capacity and 2,200 MW more wind capacity. The total solar capacity was 19,200 MW more than the Current Trends scenario though the generation expansion model added 800 MW less utility scale solar capacity. More renewable and less gas capacity additions were because of higher renewable PTC/ITC and carbon price assumptions than in the Current Trends scenario. A summary of the generation expansion results for the High Renewable Penetration scenario is shown in Table I.8.

Table I. 7: Generation Expansion Results for High Renewable Penetration Scenario

Description	Units	2019	2023	2028	2033
CC Adds	MW	1,000	-	-	1,000
CT Adds	MW	-	-	-	
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Solar Adds	MW	1,500	6,000	4,400	-
Wind Adds	MW	3,000	5,600	-	-
Annual Capacity Additions	MW	5,500	11,600	4,400	1,000
Cumulative Capacity Additions	MW	5,500	17,100	21,500	22,500
Economic Retirements	MW	-	5,610	-	-
Cumulative Economic Retirements	MW	-	5,610	5,610	5,610
Reserve Margin	%	13.0	11.6	10.0	5.3
Coincident Peak	MW	77,624	80,415	84,642	89,355
Annual Energy	GWhs	420,875	446,760	475,198	499,287
Average LMP	$/MWh	30.52	31.62	40.44	75.93
Natural Gas Price	$/mmbtu	3.25	3.32	4.18	4.48
Average Market Heat Rate	MMbtu/MWh	9.39	9.52	9.67	16.95
Natural Gas Generation	%	59.2	55.5	52.5	54.2
Coal Generation	%	4.8	2.9	5.3	6.0
Wind Generation	%	22.7	25.0	23.6	22.3
Solar Generation	%	2.6	6.8	9.2	8.8
Scarcity Hours	HRS	-	-	2.0	32.0
Unserved Energy	GWhs	-	-	6.7	46.2

Since Lubbock Power & Light integration has been approved by Public Utility Commission of Texas and its integration will potentially increase the Panhandle interface transfer capability, a sensitivity case including Lubbock Power & Light system and removing the Panhandle interface limits was created to investigate how Lubbock Power & Light integration would change generation expansion. Another sensitivity case was developed by adding another constraint on the top of the first sensitivity. The constraint was the transmission availability consideration for new wind and solar resources. An obvious impact was more wind and solar capacity was added in Panhandle because the Panhandle interface limits were removed as shown in Figure I.15. For the whole ERCOT system, more wind and less solar capacity was added with the transmission availability consideration, as shown in Figure I.16, because the transmission availability consideration was limiting solar resources as expected. Since the transmission availability consideration limited solar resources, the existing generators had less competition resulting in less retirements as shown in Figure I.17.

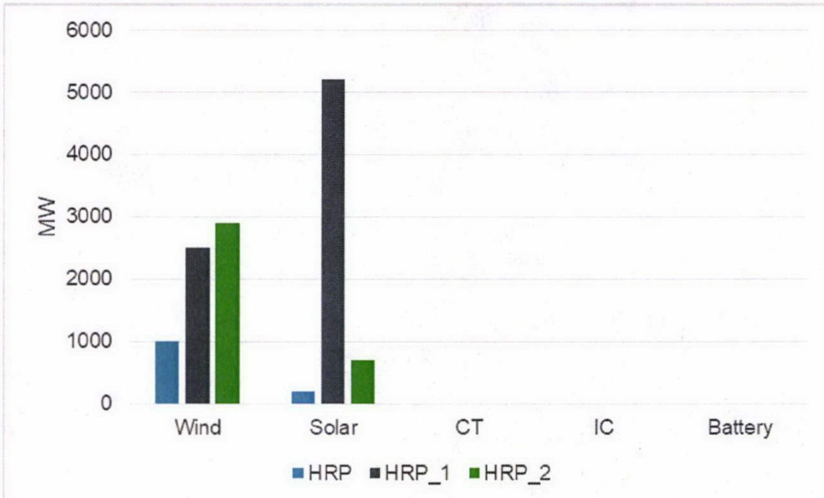


Figure I. 15: Comparison for Capacity Addition in Panhandle Region across High Renewable Penetration Scenario and Its Sensitivity Cases

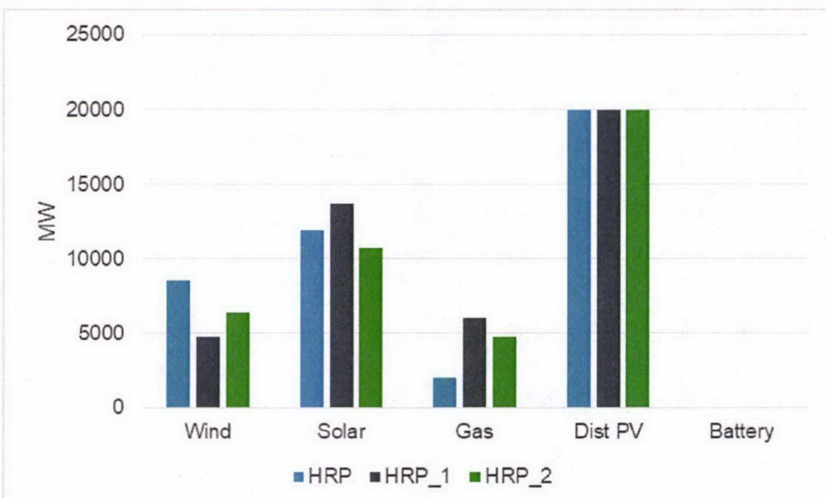


Figure I. 16: Capacity Addition Comparison across High Renewable Penetration Scenario and Its Sensitivity Cases

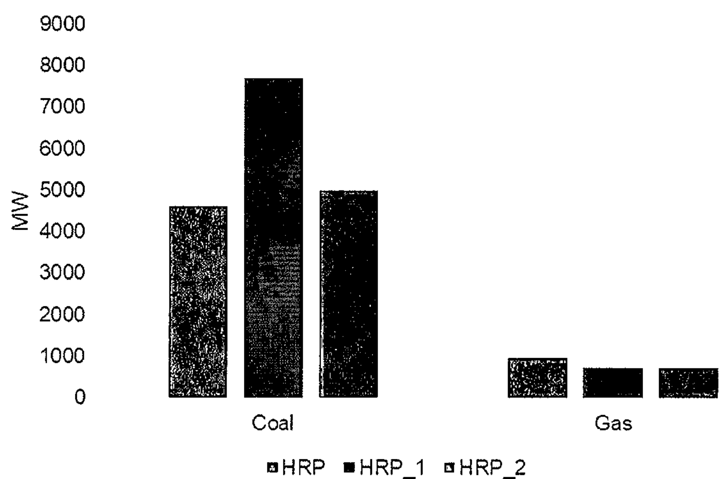


Figure I. 17: Retirement Comparison across High Renewable Penetration Scenario and Its Sensitivity Cases

High Renewable Cost

This scenario is designed to simulate a low renewable penetration condition. The solar capital cost was assumed to be higher than the other scenarios. The annual wind and solar capacity addition limits were lowered to 600 MW and 300 MW, respectively.

The model added 3,900 MW solar capacity, 300 MW wind capacity and 7,000 MW combined cycle capacity. High combined cycle capacity addition mitigated the evening scarcity issue. There were 9 potential scarcity hours in 2033 with 11,200 MW net installed capacity addition. The generation expansion results of the High Renewable Cost scenario are summarized in Table I.9.

Table I. 8: Generation Expansion Results for High Renewable Cost Scenario

Description	Units	2019	2023	2028	2033
CC Adds	MW	-	2,000	3,000	2,000
CT Adds	MW	-	-	-	
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Solar Adds	MW	300	1,200	1,500	900
Wind Adds	MW	-	-	300	-
Annual Capacity Additions	MW	300	3,200	4,800	2,900
Cumulative Capacity Additions	MW	300	3,500	8,300	11,200
Economic Retirements	MW	-	-	-	-
Cumulative Economic Retirements	MW	-	-	-	-
Reserve Margin	%	9.2	9.0	6.8	3.6
Coincident Peak	MW	78,203	83,164	88,777	94,174
Annual Energy	GWhs	423,043	459,192	500,507	537,380
Average LMP	$/MWh	26.63	28.54	43.39	57.47
Natural Gas Price	$/mmbtu	3.25	3.32	4.18	4.48
Average Market Heat Rate	MMbtu/MWh	8.19	8.60	10.38	12.83
Natural Gas Generation	%	54.8	59.0	62.4	63.9
Coal Generation	%	12.8	10.0	7.5	8.0
Wind Generation	%	20.1	18.6	17.4	16.2
Solar Generation	%	1.6	2.7	3.4	3.7
Scarcity Hours	HRS	-	-	1.0	9.0
Unserved Energy	GWhs	-	-	0.3	4.7

Emerging Technologies

The focus of this scenario was to simulate the impacts of EV adoption. Transportation electrification was assumed to start slowly but grow exponentially after reaching a certain level when charging facilities become more accessible. The adoption rates of different type of vehicles are shown in Figures I.18, 19 and 20. A summary of the generation expansion results for the Emerging Technology scenario is shown in Table I.10.

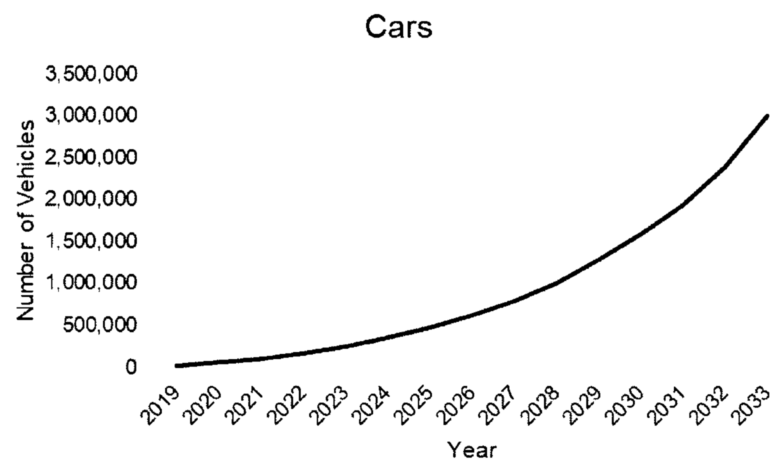


Figure I. 18: Adoption of Electric Cars during 2019-2013

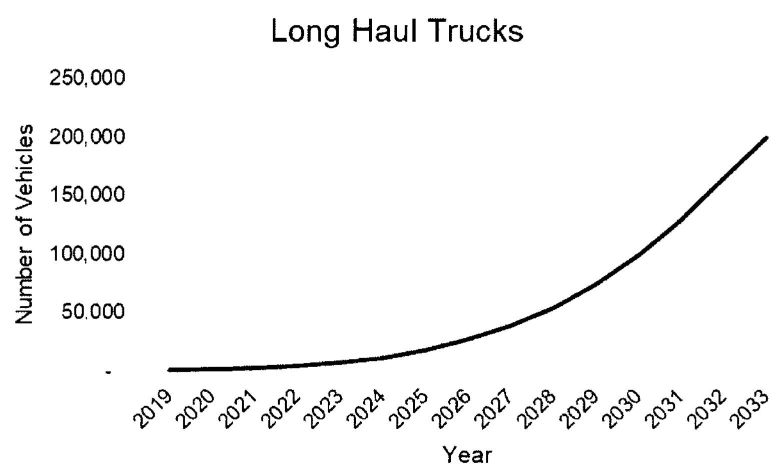


Figure I. 19: Adoption of Electric Long-haul Trucks during 2019-2013

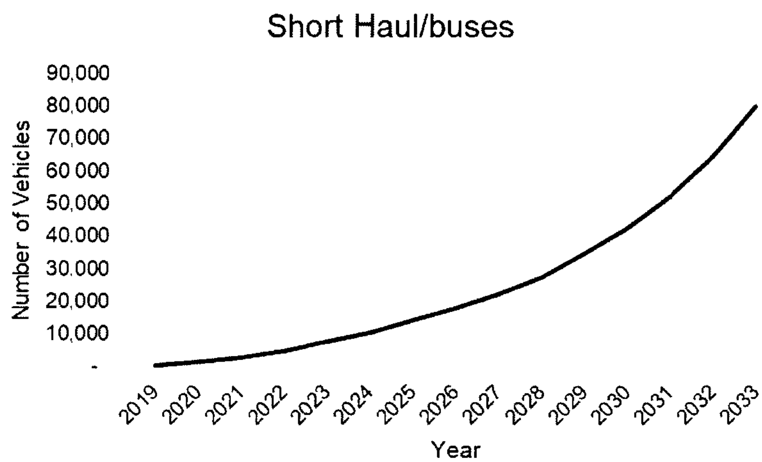


Figure I. 20: Adoption of Electric Short Haul/Buses during 2019-2013

Table I. 9: Generation Expansion Results for Emerging Technology Scenario

Description	Units	2019	2023	2028	2033
CC Adds	MW	-	3,000	3,000	10,000
CT Adds	MW	-	-	-	
Coal Adds	MW	-	-	-	-
Nuclear Adds	MW	-	-	-	-
Recip Adds	MW	-	-	-	-
Storage Adds	MW	-	-	-	-
Solar Adds	MW	1,500	5,000	1,300	-
Wind Adds	MW	2,700	1,500	300	-
Annual Capacity Additions	MW	4,200	9,500	4,600	10,000
Cumulative Capacity Additions	MW	4,200	13,700	18,300	28,300
Economic Retirements	MW	-	-	-	-
Cumulative Economic Retirements	MW	-	-	-	-
Reserve Margin	%	12.9	19.3	14.7	11.3
Coincident Peak	MW	78,235	83,832	90,740	102,492
Annual Energy	GWhs	423,359	465,059	524,263	614,043
Average LMP	$/MWh	33.60	35.44	43.30	59.64
Natural Gas Price	$/mmbtu	3.25	3.32	4.18	4.48
Average Market Heat Rate	MMbtu/MWh	10.34	10.67	10.36	13.31
Natural Gas Generation	%	58.8	59.1	58.8	64.5
Coal Generation	%	5.4	3.7	6.6	6.5
Wind Generation	%	22.5	21.7	19.6	16.7
Solar Generation	%	2.6	6.0	6.2	5.3
Scarcity Hours	HRS	-	-	-	11.0
Unserved Energy	GWhs	-	-	-	19.6

Appendix III: Generation Siting Methodology

Generation siting methodology is included in a document attached with the report

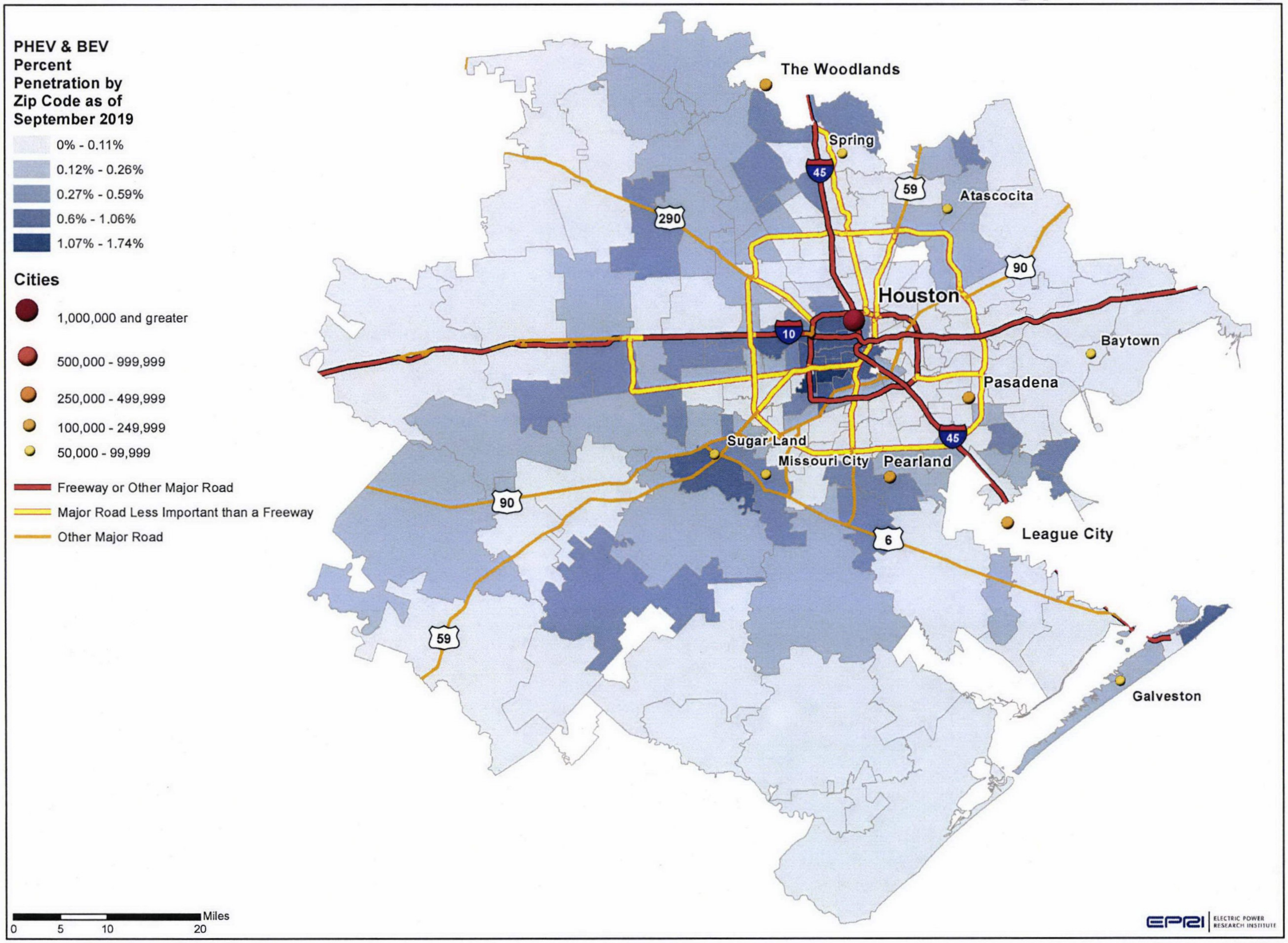
3. **Please identify any anticipated load "hot spots" in the state for electric vehicle charging. Please specify whether these hot spots are expected to result from personal, commercial short-haul, or commercial long-haul electric vehicle deployment and charging.**

The anticipated future "hot spots" for personal, or residential, electric vehicle charging will most likely begin in the areas where initial acceptance of EV technology is higher. Please see the attached heat maps, Attachments PUCT03-01 and PUCT03-02, for higher adoption zip codes in CenterPoint Houston's service territory (by % of total cars and by total quantity).

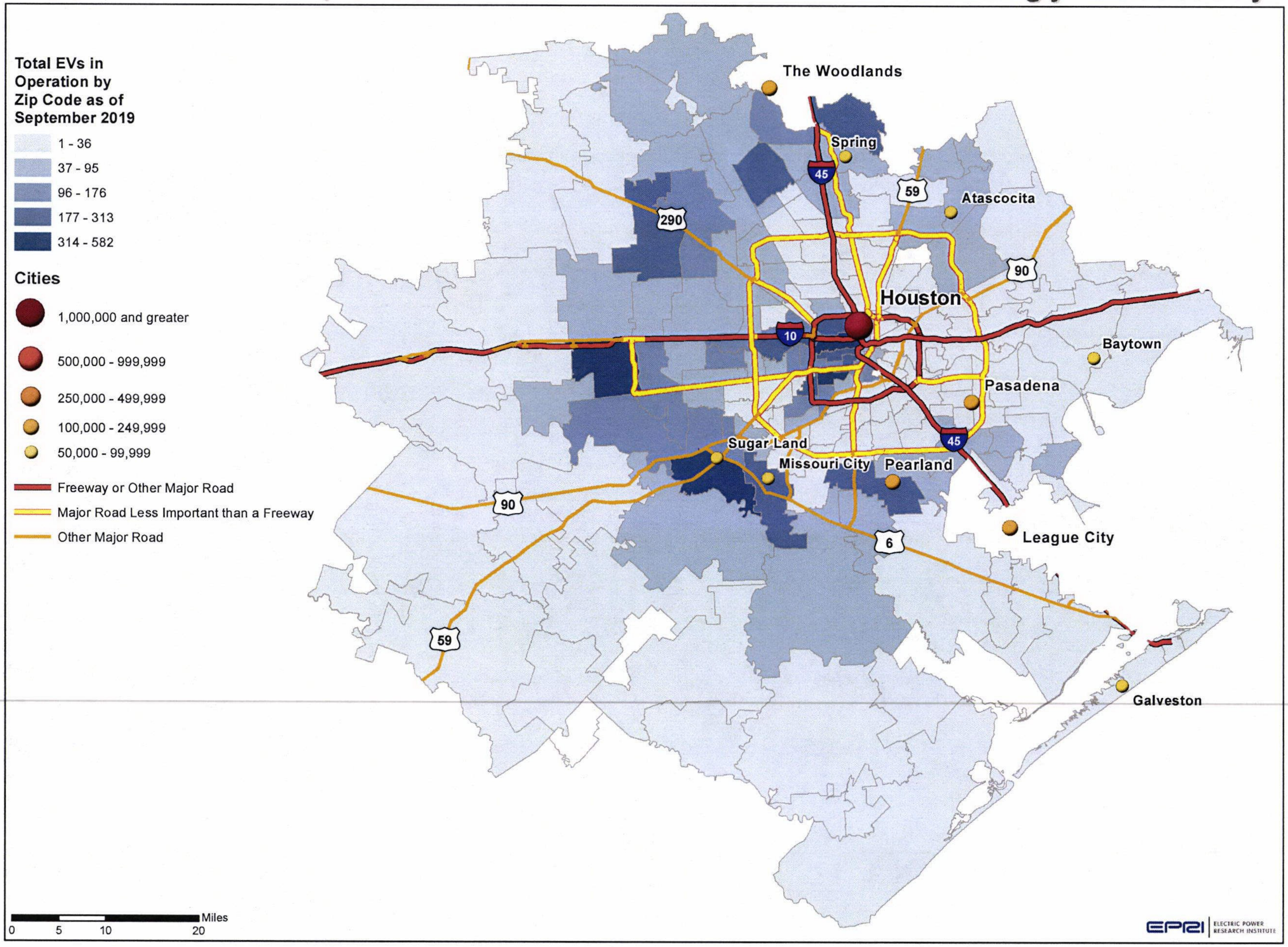
Anticipated "hot spots" resulting from commercial EV deployment would include mass transit systems (such as Metro, primary and secondary education bus systems, airport ground transportation) and private commercial courier delivery services companies (FedEx, UPS, Port of Houston operations, etc).

Attachment(s):
PUCT03-01 - Total EV Penetration (%) in the CenterPoint Energy Territory.pdf
PUCT03-02 - Total EVs in Operation in the CenterPoint Energy Territory.pdf

Total EV Penetration in the CenterPoint Energy Territory



Total EVs in Operation in the CenterPoint Energy Territory



PUCT Project 49125
PUCT03-02 - Total EVs in Operation in the CenterPoint Energy Territory.pdf
Page 1 of 1

4. **Describe the observed or anticipated load profiles and impacts of various types of electric vehicle charging stations (e.g, residential Level 1, Level 2 and Level 3 DC Fast charging) and the class of the vehicle charging (i.e., personal, commercial short-haul including fleets and buses, and commercial long-haul electric vehicles).**

Residential Level 1 and Level 2

- With increased adoption of electric vehicles, the anticipated load profile from residential Level 1 and Level 2 charging stations will likely have a step increase in late afternoon and peak during early evening. The anticipated impact could result in a shift in the system daily peak period or the addition of a second, lesser peak in the evening.

Residential DCFC

- Personal
    - Currently, there are 49 DCFC stations with 92 plugs at 31 locations, excluding Tesla, within CenterPoint Houston's service territory. Tesla has 5 sites with a total of 42 plugs. Most of these sites do not have meters that provide detailed load data (e.g., 15-minute interval data). For those that had load data available coinciding with last year's CenterPoint Houston system peak (August 14 @ 16:31), the contribution of those sites was approximately 642kW, or less than 0.004% of the total CenterPoint Houston system peak. Beyond the DCFC stations there are no individually metered charging stations to provide any insight into Level 1 or Level 2 vehicle charging for residential, public, and workplace.

- Commercial (short-haul & long-haul)
    - Currently, there are no commercial short-haul or long-haul electric vehicle charging stations within CenterPoint Houston's service territory, but we do expect installations within the near future. The anticipated load profile of these charging stations would resemble a step increase in demand, possibly during peak loading periods, or during early evening and overnight hours. If a large portion of this charging occurs during peak loading conditions, and depending on coincident factors, the impact of this increased demand could include overloaded electrical infrastructure unless some form of delayed or managed charging is available.

5. **What, if any, emerging vehicle charging technologies are anticipated to be commercially available in the next ten years that could impact electricity markets in Texas?**

CharIn EV is an international organization that is developing a standard for High Power Charging of Commercial Vehicles at a maximum of 4.5MW. This standard will also include reverse power transfer capabilities. We expect to see higher power charging as larger concentrations of heavy-duty vehicles develop with commercial sites requiring electric service of 20-30 MW.

6. **The Commission requests that parties provide a detailed explanation on the following items:**

    a. **The anticipated impacts of electric vehicle charging, including residential and commercial charging stations of the distribution system in the next ten years;**

    Residential: Assuming the electric vehicle penetration rate remains at the same level the Company has observed in the last 2 years, the anticipated impact of residential electric vehicle charging should be minimal. The contribution of residential charging thus far has remained at a level well within our overall load growth projections. However, with a significant increase in this rate (such as the high rate of EV growth projected in the Company's response to Question 1), we could expect to see either an increase and shift in the timing of the daily peak demand and/or a secondary, lesser peak demand in the late evening, depending on coincident factors.

    Commercial: The anticipated impact of commercial electric vehicle charging poses a greater impact to the distribution system within the next ten years. If unmanaged, charging during the peak load periods will increase the peak demand and likely require modifications to the distribution system and/or increases in generation. Managed charging, such as controlled charging or time-of-use pricing can help to mitigate these unfavorable impacts by encouraging charging during off-peak periods.

    b. **The anticipated impact of electric vehicle charging stations on the transmission system in the next ten years; and**

    If there is a substantial increase in EV adoption within the next 10 years (see response to Question 1), it is anticipated that there would be a significant change in the system load profile. As an example, the system peak load hour could shift to later in the day (e.g. from 1700 to 2200). The load profile and generation expansion implications of the changing load shape suggest that EV adoption and resulting vehicle charging patterns should be monitored in the upcoming years.

    The potential transmission level impacts of this phenomenon, particularly during summer peak conditions, may result in no longer being able to take advantage of transmission outages at night to complete work during the summer and still be able to comply with ERCOT Summer outage restrictions.

    c. **The anticipated impact of electric vehicle charging stations on long-term system planning at the regional transmission organization level, given a widespread adoption scenario.**

    Assuming widespread adoption of EVs, long-term system planning may need to account for any changes to system peak load conditions. A recent ERCOT long-term, system assessment indicated that, assuming a high adoption rate of EVs, it is forecasted that the magnitude of the system peak could be approximately 15% higher than conventional load. It would therefore be advisable for transmission service providers or TSPs to include sensitivities to their load projections when performing long-term system planning. This may introduce some uncertainties as to when to complete transmission system upgrades to support these higher level of system peak loads due to EV adoption.

Another consideration to system planning related to EV adoption is the increased importance of capturing the dynamic behavior of these loads either while in its charging state or while contributing power to the grid. Research is still needed to properly reflect how these types of loads respond from a dynamic behavior perspective. Because of the potential changes in load profile, dynamic behavior, and peak load level, the need may arise for creation of additional planning study models beyond the typical summer peak load and minimum load models used today to cover a wider range of stressed operation conditions.

7. **What is the overall anticipated impact of electric vehicle charging in the next ten years in terms of energy and peak demand? What changes, if any, should be made to energy and peak demand forecasts to incorporate this impact?**

As electric vehicle (personal and commercial) penetration rates increase within the next ten years, we anticipate the peak demand to increase above the typical 2% - 4% per year load growth we have recently experienced, even with managed charging and/or time-of-use pricing programs in place. The late afternoon daily demand peak that CenterPoint Houston has typically experienced may be followed by a lower, secondary daily peak in the early to late evening, predominantly driven by commercial vehicle charging. Without managed charging programs available, the peak demand (during typical peak periods) will likely reach levels requiring capital projects to mitigate loading issues (new substations, transformers, feeders, overhead, etc.). If the rate of electric vehicle adoption increases above recent levels, the Company's Electric Distribution Planning (EDP) will review the existing annual load forecasting algorithms and make necessary adjustments to maintain pace with the increased load growth due to electric vehicle charging.

As indicated in response to Question 6c, assuming a high rate of adoption of EVs within the next 10 years, it is possible that there could be a 15% increase in energy and peak demand. Sensitivities to energy and peak demand forecasts may be needed to account for this uncertainty.

8. **What are the capabilities of electric vehicle related technologies, such as vehicle-to-grid, to participate in wholesale electricity markets?**

In theory, Vehicle-to-grid (V2G) technologies have numerous capabilities for grid management, but actual application has been limited to date. V2G will enable the use of electric vehicle batteries to assist in supporting grid reliability and better integration of intermittent renewable generation. Larger batteries such as those found in electric transit and electric school buses can plug in and help stabilize the grid and help meet system peak demands. These same batteries can be used to supply electricity during a power outage and used as mobile power supply in support of local emergency management. V2G also offers the grid more flexibility compared to managed charging (V1G). Managed charging primarily benefits the grid during peak load hours and once the battery is full no grid services can be provided. V2G offers the ability to discharge to the grid, effectively increasing the kW capacity available for peak load reduction, and the discharge can be effectively timed to be coincident with peak loads independent of when the PEV (Plug-in Electric Vehicle) would have been charging.[1]

To better understand the capabilities of V2G in the Texas market, pilot projects could be enabled with goals of identifying the impact to provide peak reduction, quantify ancillary service revenue, and provide the opportunity to EV owners for energy arbitrage during renewable overgeneration.

From a longer-term perspective, as these technologies that export to the grid become more prolific, the distribution grid will need to evolve in key ways to achieve the expected reliability and peak load management goals. At a high-level, the grid will need to evolve in four ways:

- Visibility will need to be enhanced to better understand the amount of power being taken off and exported on to the grid by these applications in near real time. Beyond load, better information will need to detect conditions such as phase imbalances.
- Back-end systems will need to be upgraded to gather these new types of data and, more importantly, process the data, formulate recommendations to adapt the grid and ultimately execute those recommendations. The modeling required to do this is highly complex and performing this modeling in near real time will require high volumes of processing capacity to perform these functions quickly.
- As the grid becomes more dynamic, grid stabilization capabilities (such as Volt/VAR optimization) will be necessary. And in situations where the volume of DERs available exceeds the hosting capacity of the infrastructure, ways to provide permissive signaling to the resources that have permission to operate will have to be developed.
- As the volume of resources grow, distribution planning models will become more sophisticated, so infrastructure needs can be planned to optimize the system.

The enhancements required to achieve the optimal dynamic grid will be substantial. From the utility perspective, the conversation inevitably raises questions about the timing and recoverability of those investments. Further questions are raised about scenarios where a decision must be made about which DER resources have permission to operate when the available supply exceeds the hosting capacity of the distribution infrastructure.

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[1] Electric Power Research Institute, Open Standards-Based Vehicle-to-Grid, Value Assessment.
EPRI Open Standards-Based Vehicle-to-Grid Value Assessment 2019.pdf pg. 5-20

9. **Please explain any preferred or best practice facilities siting and design standards for commercial electric vehicle charging stations and why such standards are recommended.**

From the Electric Distribution Planning (EDP) perspective, general siting recommendations include the following.

- Areas where existing overhead facilities are readily available and easily accessible are preferred. These areas will maximize the service options and flexibility while providing lower installation and maintenance costs.
- In general, siting in areas where existing distribution facilities are entirely underground are not recommended due to limited available capacity and increased costs for installation and maintenance.

Based on the light-duty forecast in question 1, to support the medium case in 2030 of approximately 164,000 EVs, the Department of Energy's EVI-Pro Lite tool[2] estimates the Greater Houston area will require the following infrastructure:

- 9,397 Workplace Charging Level 2 Plugs
- 5,904 Public Level 2 Plugs
- 629 DC Fast Charging Plugs

Specific impacts are unknown, but utility investment in pilot projects could have the following goals:

- Develop an understanding of electric vehicle charging behaviors and the effects of light-duty and medium-/heavy-duty vehicles have on CenterPoint Houston's distribution and transmission systems
- Fill in underserved DCFC locations by developing an evacuation route strategy to enable mass evacuation of electric vehicles during natural disasters. Also, focus on disadvantaged communities.
- Develop programs to identify best practices for managing charging loads.
- Encourage the competitive market investment in electric vehicle charging services
- Coordinate with Texas Commission for Environmental Quality ("TCEQ") to leverage the Volkswagen Settlement Environmental Mitigation trust funds specifically for ZEV Infrastructure.

One pilot program that would be valuable in understanding impacts to the grid, support by charging providers and increased availability of charging ports is a "make ready" program, where the electric utility installs, owns, and maintains conduit and wiring to "ready" a customer site for the installation of charging equipment, as well as any distribution upgrades or service extensions needed to serve that site. The charging equipment itself is procured, owned and paid for by the private investor. The electric utility also could offer a rebate to offset the cost of the charging equipment. A variant on the "make ready" approach could include a combination of line extension costs and a rebate for installation work on the customer side of the meter. The electric utility would not own any infrastructure on the customer side of the meter. This model provides an opportunity for electric utilities to gain upfront knowledge on the system

[2] See https://afdc.energy.gov/evi-pro-lite

requirements for managing the loads from public EV charging stations and better design and plan for power demands involved with charging infrastructure implementation.