2026 PNM Distribution System Plan

1ST STAKEHOLDER MEETING – JULY 31ST, 2026

PNM®

WELCOME AND SESSION GUIDELINES

- During presentations, please hold your questions until the Q&A sessions.
- **Please state your name and organization when offering a comment or question.**
- Please keep yourself muted to minimize background noise
- This is a process for stakeholder input, not a litigated proceeding.
- Be respectful in your comments.
- We are all working with good intentions; give each other the benefit of the doubt.
- Share your ideas; leave time for others.

AGENDA

- Welcome and Introductions
- Stakeholder Engagement and Timeline
- Regulatory Landscape
- Current Distribution System
- Distribution Planning Process and 10 Minute Break
- Vision for Distribution System
- Financial Information and Benefit-Cost Analysis
- Action Plan and Key Metrics
- Stakeholder Q&A and Feedback

SAFE HARBOR STATEMENT

Statements made in this document that relate to future events or Public Service Company of New Mexico's (PNM) expectations, projections, estimates, intentions, goals, targets, and strategies are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based upon current expectations and estimates. Because actual results may differ materially from those expressed or implied by these forward-looking statements, PNM cautions readers not to place undue reliance on these statements. PNM's business is influenced by many factors, often beyond PNM's control, which can cause actual results to differ from those expressed or implied by the forward-looking statements. For a discussion of risk factors and other important factors affecting forward-looking statements, please see PNM's Form 10-K and Form 10-Q filings with the Securities and Exchange Commission, the factors of which are specifically incorporated by reference herein. PNM assumes no obligation to update this information, except to the extent the events or circumstances constitute material changes in the Distribution System Plan that are required to be reported to the New Mexico Public Regulation Commission.

STAKEHOLDER COMMENT PROCESS

- **Stakeholder Outreach**
- **Stakeholder Engagement #1** 7/31
- **PNM Draft DSP** 7/31
- **30-day Stakeholder Comment Period** 8/31
- **PNM Response to Comments**
- **Stakeholder Engagement #2** 9/21
- **PNM Files 1st DSP** 10/1

PNM is seeking feedback to improve the DSP.
Written comments can be submitted using PNM's feedback form and will be accepted through 8/31/26. Survey form is available on PNM's Distribution System Planning website: pnm.com/distributionsystemplan

Responses can be emailed to distributionsystemplan@pnm.com
starting today through August 31, 2026

STAKEHOLDER ENGAGEMENT

- Stakeholder engagement is a critical component of PNM's Distribution System Planning process and helps ensure the DSP reflects customer needs, emerging technologies, policy developments, and evolving grid requirements.
- Promotes transparency by providing visibility into planning assumptions, methodologies, and proposed investments.
- Incorporates diverse perspectives from customers, communities, regulators, tribes, developers, technology providers, and public-interest organizations.
- Supports informed planning decisions related to reliability, resilience, affordability, grid modernization, transportation electrification, and DER integration.
- Provides stakeholders with meaningful opportunities to review the DSP, submit comments, and help shape future planning priorities.
- Creates a documented process for stakeholder feedback, PNM responses, and continuous improvement of future DSPs.

Team Introductions

DSP CONTRIBUTORS | DISTRIBUTION PLANNING

- **LAURIE A WILLIAMS**
  Senior Vice President, PNM Integrated Planning & Transmission Development
  - **ERFAN HAKIMIAN**
    Director, Transmission and Distribution Planning & Contracts
  - **CINDY BUCK**
    Manager, Engineering Distribution Planning
    - **CHARLOTTE A OTERO-GOODWIN**
      Engineer IV
    - **ABUL HASAN EMU**
      Engineer III

DSP CONTRIBUTORS | DISTRIBUTION OPERATIONS

PNM OPERATIONS & ENGINEERING

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Senior Vice President, PNM Operations

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Manager, Control Systems

NM OPS PPMO

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DSP CONTRIBUTORS | DISTRIBUTION ENGINEERING AND DER

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DISTRIBUTION ENERGY ENGINEERING

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DSP CONTRIBUTORS | GRID MODERNIZATION

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DSP CONTRIBUTORS | VEGETATION, EFFICIENCY & ELECTRIFICATION

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ENERGY EFFICIENCY & ELECTRIFICATION

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JOHN WILLIAMSON
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DSP CONTRIBUTORS | FINANCE AND BUSINESS SUPPORT

BUSINESS OPERATIONS SUPPORT

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Associate Director, PNM Business Operations

COST OF SERVICE

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JOHN VERHEUL
Attorney III

STRATEGIC MARKETING & PRODUCT MANAGEMENT

JULIO C AGUIRRE CARMONA
Director, Pricing Customer Strategy

ASLAM T HAYAT
Manager, Load Forecasting

Background and Overview

DSP REGULATORY HISTORY

The Commission moved from statutory direction and rule development to a one-time distribution system plan filing.

MARCH 3, 2020	APRIL 20, 2022	FEBRUARY 6, 2025	JANUARY 29, 2026
HB 233 SIGNED	**DOCKET CREATED**	**FORMAL NOPR ISSUED**	**ONE-TIME DSP REQUIRED**
The "Energy Grid Modernization Roadmap" becomes law and adds the Grid Modernization Statute to the Public Utility Act.	The Commission narrows the inquiry and creates Docket No. 22-00089-UT.	The Commission begins formal rulemaking on a proposed grid-planning rule.	The Commission terminates the rulemaking and directs PNM to file a one-time DSP by October 1, 2026.

CURRENT FILING: PNM's 2026 DSP is the Commission-directed one-time filing that replaced adoption of the proposed formal rule.

PURPOSE OF THE DSP

01 **FORWARD-LOOKING FRAMEWORK**

Maintain a distribution system that is:

SAFE | RELIABLE | RESILIENT | FLEXIBLE | AFFORDABLE

02 **550,000+ CUSTOMERS**

Planning supports service while preparing for:

- Load growth and economic development
- Transportation and building electrification
- Distributed energy resources • Community solar • Storage
- New Mexico's transition toward carbon-free electricity

03 **DER PLANNING NEEDS**

Increasing DER penetration creates needs around:

Forecasting | Hosting Capacity | Voltage Management | Reverse Power Flow | Protection & Communications | System Visibility

04 **GRID MODERNIZATION PROVIDES**

Advanced Metering Infrastructure
Telecommunications
Distribution Automation
Advanced Distribution Management System
Distributed Energy Resources Management
Volt/VAR Optimization
Cybersecurity
Improved Network Models

Regulatory Landscape

STATE RULES AND REQUIREMENTS

Public Utility Act

Rule 560 —service standards

Grid Modernization and Rule 588

Efficient Use of Energy Act — EE/DR and Non-Wires Alternatives

Rule 574 — Transportation-electrification

Rule 568 — Interconnection <10 MW

Rule 569 — Interconnection >10 MW

Rule 570 — QF and Co-gen

Rule 573 — Community Solar

NMAC 17.7.3 — Integrated Resource Plans

Rule 440 – T&D projects > $1 million

FEDERAL REQUIREMENTS

Federal Energy Regulatory Commission ("FERC") Governance

FERC Small Generator Interconnection Procedures (SGIP)

Order 2023 reforms LGIP processes

Order 1920 long-term regional transmission planning

Order 2222 DER aggregations in markets

REGIONAL MARKETS

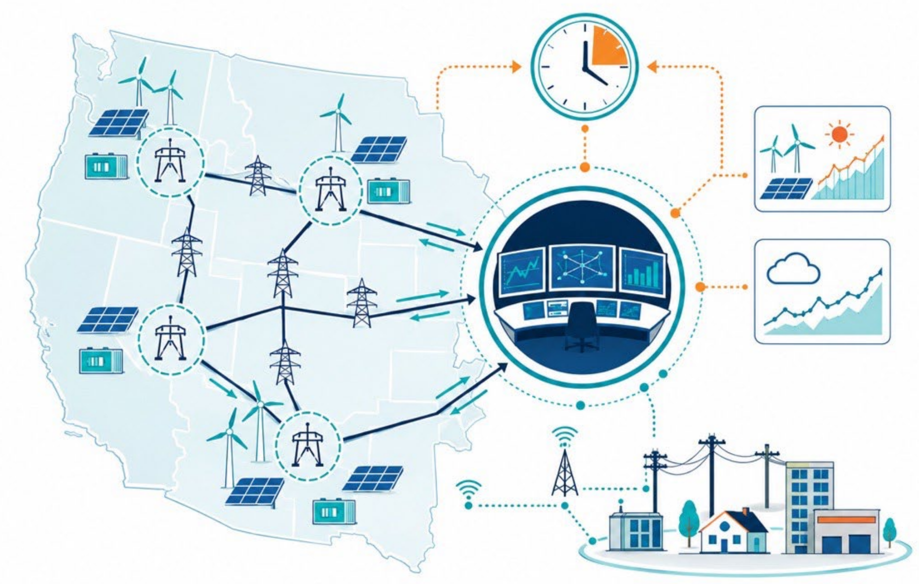
Expand access to regional energy sharing and day-ahead price signals.

Enhance value of resources through optimized dispatch.

Support renewable integration, reliability, and efficient grid operations.

Require increased forecasting, communications, telemetry, and utility coordination.

Require operations to meet distribution, interconnection, and market requirements.



Current Distribution System

PNM SERVICE TERRITORY OVERVIEW

Proudly serving Greater Albuquerque, Rio Rancho, Los Lunas, Belen, Santa Fe, Las Vegas, Alamogordo, Ruidoso, Silver City, Deming, Bayard, Lordsburg, and Clayton. In addition to these cities and towns, PNM also provides electricity to several tribal communities, including the Tesuque, Cochiti, Santo Domingo, San Felipe, Santa Ana, Sandia, Isleta, and Laguna Pueblos.

TYPICAL DISTRIBUTION SYSTEM VOLTAGES AND EQUIPMENT

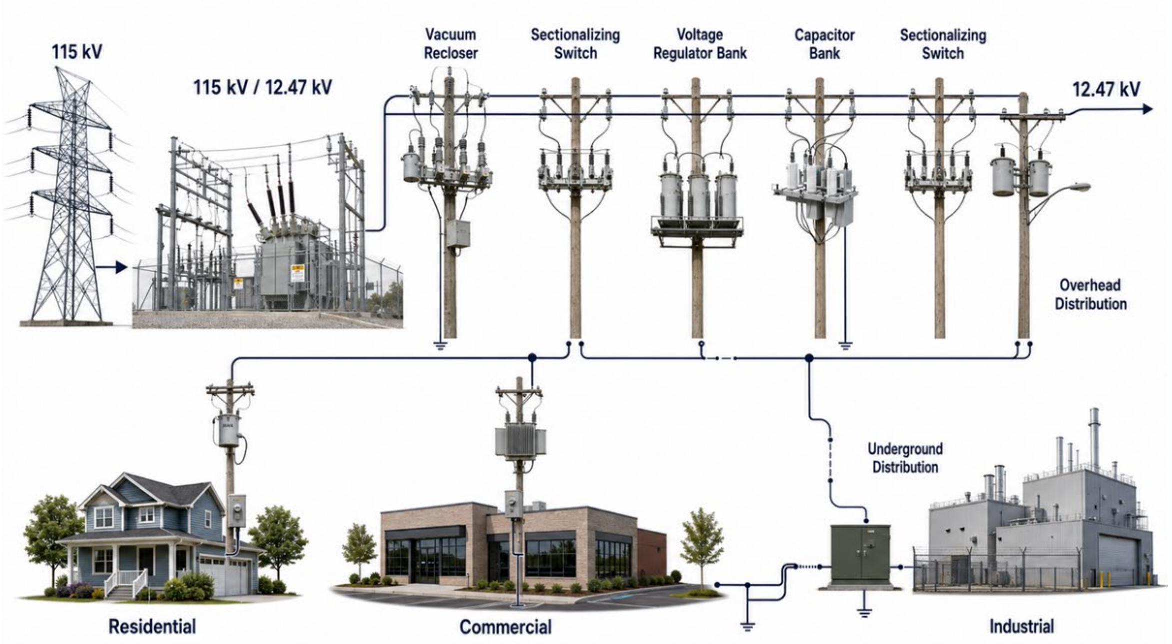
Power is stepped down in stages for safe, efficient delivery.

TYPICAL VOLTAGES

- 115 kV Utility source
- 115 / 12.47 kV Substation transformer
- 12.47 kV Primary distribution feeders
- 120/240 V or 480Y/277 V Customer service

COMMON EQUIPMENT

- Substation transformers and breakers
- Reclosers and sectionalizing switches
- Voltage regulators and capacitor banks
- Overhead and underground transformers



PNM 15 Planning Divisions: Valencia, Alamogordo, East Mountain, Clayton, Deming, Las Vegas, Lordsburg, Ruidoso, Sandoval, Santa Fe, Silver City, ABQ Central, ABQ East, ABQ South & ABQ West

DISTRIBUTION SUBSTATION TRANSFORMER CAPACITY

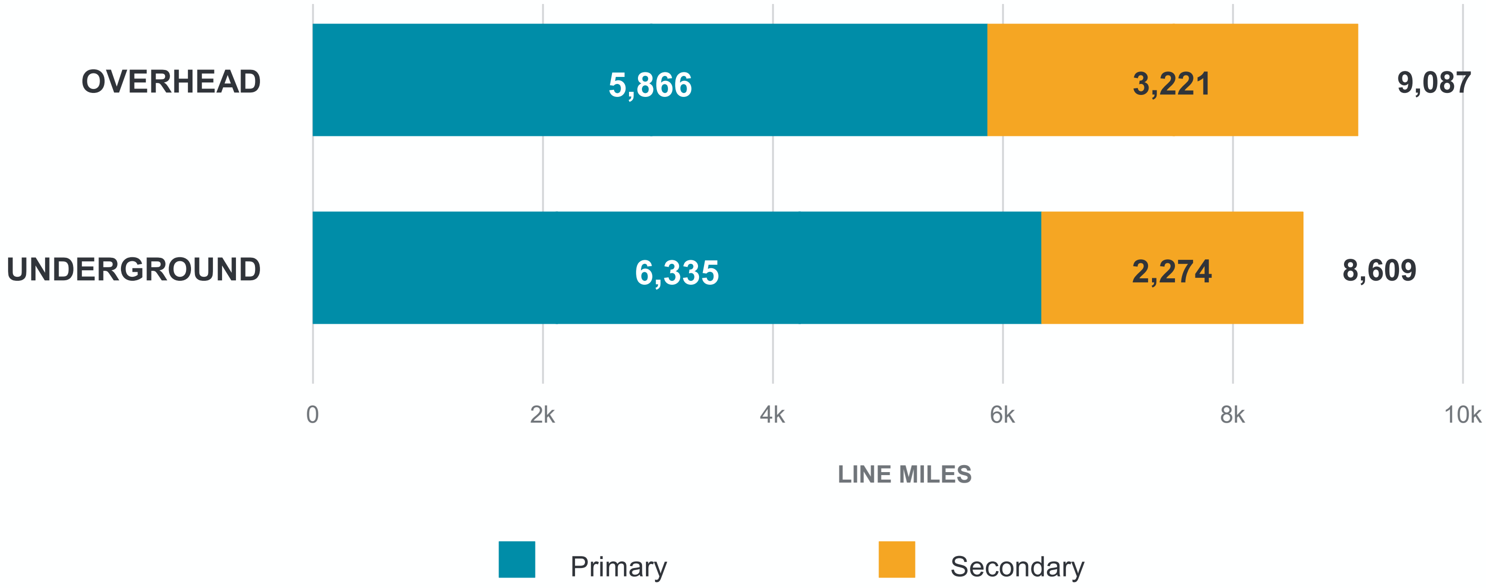
Area	Energized substation transformers	Connected Nameplate Capacity (MVA)
Northern New Mexico	39	475.8
Central New Mexico	128	3,169.4
Southern New Mexico	30	367.6
PNM total	197	4,012.7

DISTRIBUTION OVERHEAD AND UNDERGROUND LINES

PRIMARY AND SECONDARY LINE MILEAGE

OVERHEAD TOTAL • 9,087 MILES

UNDERGROUND TOTAL • 8,609 MILES



FEEDER SCADA CONTROL STATUS

Control Status	Feeder Positions	Percentage of SCADA Feeders
SCADA control	602	97.7%
Manual control	14	2.3%
PNM total	616	100.0%

SCADA: Supervisory Control and Data Acquisition

DRIVERS IN PLANNING

- Reliability Metrics and System Performance
- Resources Interconnections
- Growth – EV, Electrification, Economic Development
- Public Safety Considerations – High Fire Risk Area (HFRA)
- Legacy or Aging Infrastructure
- Emergent System Conditions

RELIABILITY PERFORMANCE METRICS, 2021–2025

Year	SAIDI (minutes per customer)	SAIFI (interruptions per customer)	CAIDI (minutes per interruption)
2021	86.22	0.742	116.12
2022	101.33	0.783	129.39
2023	92.17	0.726	127.01
2024	124.45	1.008	123.51
2025	116.51	0.868	134.30

SAIDI: System Average Interruption Duration Index
SAIFI: System Average Interruption Frequency Index
CAIDI: Customer Average Interruption Duration Index

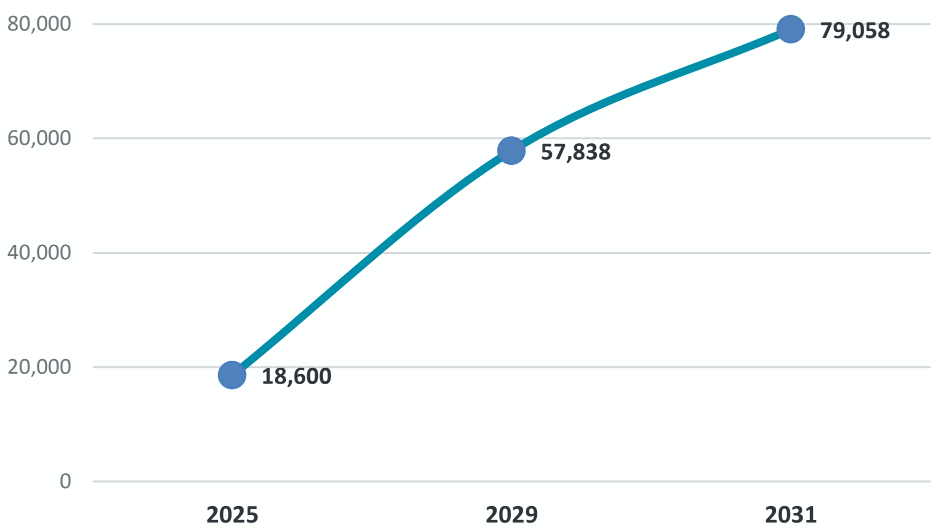
DISTRIBUTION-CONNECTED DER BY TECHNOLOGY

Technology	Installations	Installed Capacity (MW)
Solar (excluding Community Solar)	47,540	597.100
Community Solar	9	42.750
Customer Battery	1041	38.705
PNM Distributed Sited Battery Energy Storage	2	12.000
Other DER	43	2.074
PNM total	48,635	692.629

ELECTRIC VEHICLE AND CHARGING OUTLOOK

LIGHT-DUTY EV OUTLOOK

6.8% → 11.0% → 13.0% ADOPTION

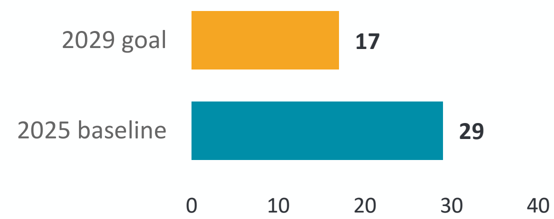


PUBLIC CHARGING

645
PUBLIC PORTS AT YEAR-END 2025

2,757
ADDITIONAL PORTS NEEDED BY 2029

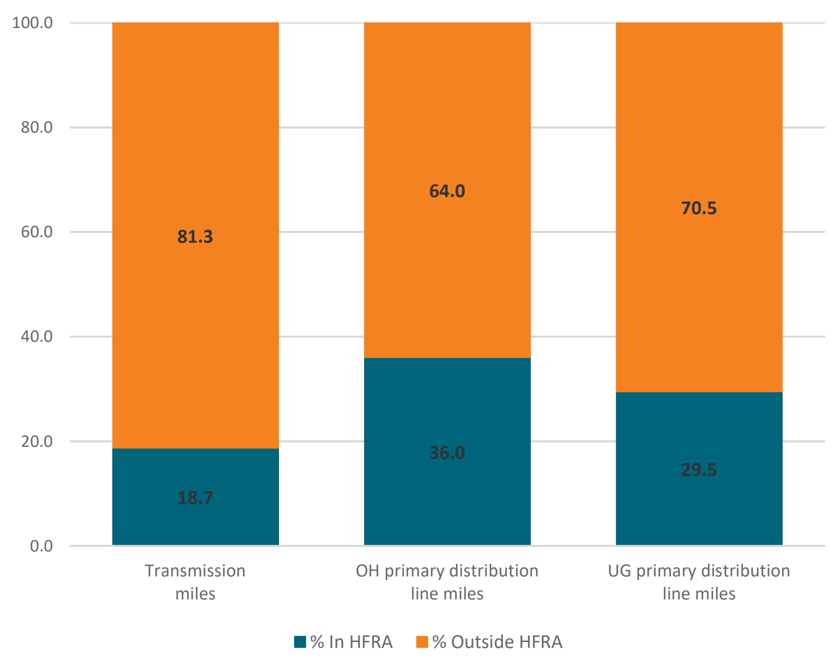
EVs PER PUBLIC PORT



PROPOSED PROGRAM COVERAGE

HIGH FIRE RISK AREAS (HFRAS)

LINE MILE PERCENTAGE INSIDE AND OUTSIDE HFRAs



36% OF OVERHEAD PRIMARY DISTRIBUTION LINE MILES ARE INSIDE PNM'S HFRAs

5,119.54 TOTAL DISTRIBUTION LINE MILES IN HFRAs

DISTRIBUTION LINE MILES INCLUDE:
- Primary overhead distribution line
- Secondary overhead distribution line
- Primary underground distribution line
- Secondary underground distribution line

RISK MITIGATION ACTIVITIES

- Grid hardening and vegetation management, including cyclical (proactive) trimming and clearing
- PNM weather stations and ignition-detection cameras
- Public Safety Power Shutoff
- Wildfire Safety Mode to reduce infrastructure ignition risk
- Community engagement, outreach and education
- Partnerships with State, Federal, Tribal and Municipal stakeholders, land managers, emergency management and first responders

Source: "Line mile percentage inside and outside HFRAs," 2026 Wildfire Mitigation Plan. Plan filed with the NMPRC on April 1, 2026.

LEGACY OR AGING INFRASTRUCTURE

- PNM monitors equipment age and condition through routine inspections and its Asset Management Database to manage maintenance, refurbishment, or replacement.
- New Mexico’s relatively mild climate and limited exposure to natural disasters allow PNM to achieve longer useful lives from many distribution assets.
- Despite favorable operating conditions and strong maintenance practices, aging infrastructure still requires upgrade - replace before failures occur in the field.
- The most significant aging infrastructure concerns include live-front padmount transformers and switchgear, open-wire secondary installations, and aging poles and underground cables.
- PNM uses a risk-based prioritization process to target these critical asset categories through ongoing capital investment programs designed to maintain safety, reliability, and system performance.

EMERGENT SYSTEM CONDITIONS

- Emergent conditions can occur as a result of lightning, equipment failure, or accidents, such as cars hitting utility poles.
- PNM periodically experiences these conditions and quick response is needed to repair and restore elements in the field.
- When this occurs, PNM generally treats it as an emergency condition and endeavors to resolve the issue as promptly as safe and practicable.

Distribution Planning Process

DISTRIBUTION PLANNING PURPOSE

- PNM uses Distribution Planning to translate customer load, distributed energy resource activity, asset capability, operating constraints, and long-term service expectations into practical distribution system investments and operating state
- PNM's Distribution Planning process provides a structured, data-driven approach to identify system needs, evaluate alternatives, and deliver reliable, cost-effective infrastructure investments for the future grid technologies for current and future conditions

PLANNING FRAMEWORKS

SYSTEMWIDE

01

TEN-YEAR DISTRIBUTION SYSTEM PLAN

Annual systemwide assessment of load growth, capacity, reliability, and hosting capacity on a ten-year look ahead.

CONTINGENCY

02

SUBSTATION OUTAGE

Evaluate contingency performance.

LOCAL NEEDS

03

RECONFIGURATION & AREA STUDIES

Operational Solutions and detailed analysis of local system needs and upgrade options.

DER READINESS

04

INTERCONNECTION & HOSTING CAPACITY ANALYSIS

Assess DER integration and available system capacity.

PROJECT LIFECYCLE-FROM SYSTEMWIDE SCREENING TO PROJECT TRANSITION

Service Territory
PNM system-wide planning context

→

Division
broader operating or planning area

→

Cluster
related feeders and substations

→

Area Study
detailed engineering review

→

Project Transition
scope, timing, design, and budget review

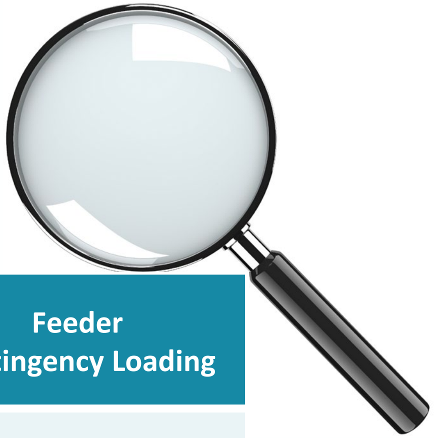
KEY OUTCOMES

01 IDENTIFY — Identifies future capacity and reliability constraints.

02 PRIORITIZE — Prioritizes operational improvements, targeted upgrades, and non-wires alternatives.

03 REFINE — Refines project scope, timing, and cost before design and construction.

DISTRIBUTION PLANNING CRITERIA AT A GLANCE



Normal Transformer Loading	Contingency Transformer Loading	Equipment / Conductor	Normal Voltage	Feeder Contingency Loading
≤80% normal rating	≤90% emergency rating	≤100% normal rating	118.7–126 V	≤550 A highest phase

Other criteria: feeder load ≤430 A; restoration steps typically ≤2 normal + 1 supplemental switch plans.

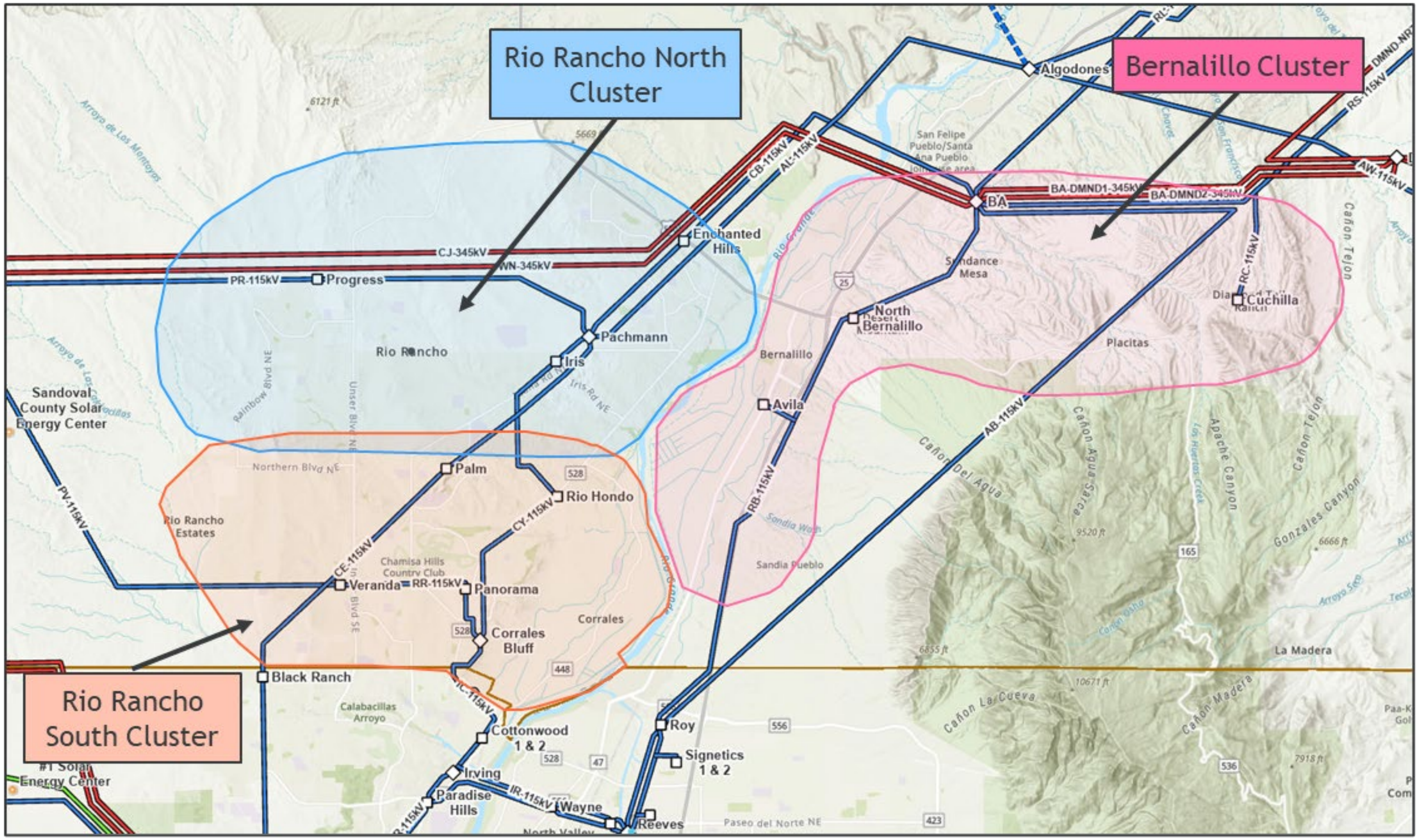
RELATIONSHIP BETWEEN PNM PLANNING REVIEW LEVELS

Planning Level	Primary Purpose	Typical Outputs	How Results Are Used
Ten-Year Plan	Screen the system by division and cluster using historical loading, forecast loading, area contingency capacity, DER information, and all known new-load inputs.	Transformer load forecasts, cluster summaries, high-level area contingency results, potential project timing, preliminary costs, and high-level hosting capacity indicators.	Identifies planning criteria for concerns and potential investments. Results are indicators and do not, by themselves, establish a final project scope.
Substation Outage Review/Contingency Study	Evaluate a single substation transformer outage can be successfully restored by adjacent feeders/substations	Phase balancing, potential feeder ties, switching actions, reconductoring, load transfers, voltage device changes, and other smaller-scope mitigations.	Provides operation plans for peak load outage solutions. When operational issues are found, the need is escalated to a more focused area study.
Reconfiguration / focused engineering review	Evaluate whether near-term operational actions can address a planning concern before a major capital project is proposed.	Potential feeder ties, switching actions, reconductoring, load transfers, voltage device changes, and other smaller-scope mitigations.	Documents whether operational fixes are feasible, durable, and sufficient. If not, the need is escalated to a detailed area study.
Detailed Area Study	Perform engineering analysis for a geographic area or planning cluster where system issues are significant or where a major project may be required.	Power-flow model results, normal and contingency performance, alternative solutions, sensitivity analysis, solution comparison, project descriptions, cost estimates, and schedule assumptions.	Confirms the need, scope, location, timing, and planning justification for major capacity or reliability investments.
Hosting Capacity Analysis	Evaluate the ability of feeders and related facilities to host additional DER without causing thermal, voltage, protection, or operational concerns.	Base-case hosting capacity, system improvement scenarios, sensitivity results, public-facing summary information, and DER integration insights.	Supports interconnection review, DER planning, grid modernization, and identification of hosting capacity improvement projects.

MAJOR INPUTS AND OUTPUTS IN THE TEN-YEAR PLAN PROCESS

Ten-Year planning input or step	How it is used in the planning process
PNM verified peak/minimum load SCADA data	Establishes the existing loading baseline and supports both peak-load and minimum-daylight-load analysis.
Solar irradiance profile	Supports analysis of rooftop PV, large-scale PV, and coincident solar output assumptions.
Study start year, division, and cluster inputs	Defines the planning area and study horizon used to populate cluster tables and reporting summaries.
Five-year historical transformer loading	Provides the basis for applied transformer growth rates and the 10-year load forecast.
New load interconnections and economic development inputs	Adds known or expected customer loads to the forecast when a project is sufficiently defined.
Detailed Area and Reconfiguration studies performed with Synergi power flow analysis and forecast-evaluation projects	Shows how previously proposed or newly identified projects would change transformer loading, load transfers, and cluster capacity.
N-1 contingency tables	Evaluates remaining area emergency capacity under existing system, future load, and project scenarios.
Hosting capacity section	Captures BESS, community solar, approved generation, and other data used for high-level hosting capacity indicators.

PLANNING BY DIVISION AND CLUSTER



NET LOAD AND GROSS LOAD ANSWER DIFFERENT RISK QUESTIONS

NET LOAD

- Load observed by the grid after customer-sited or local generation.
- The current Ten-Year Plan commonly uses net load for transformer-loading review.

Vs.

GROSS LOAD

- Underlying customer demand before local generation reduces grid-observed load.
- Helps expose high load under low-solar conditions, large DER outage, inverter behavior, and electrification risk.

FORECASTS

COMBINE HISTORY + KNOWN ADDITIONS + ENGINEERING REVIEW

01 FIVE-YEAR HISTORY

Use historical transformer peak loading to establish a growth rate.

02 ENGINEERING REVIEW

Review abnormal peaks; transfers, outages, equipment changes, and abnormal configurations may be adjusted or excluded.

03 10-YEAR HORIZON

Forecast normal-configuration loading across the ten-year horizon.

04 KNOWN ADDITIONS

Add sufficiently defined new loads, economic development, and proposed planning projects.

05 CONSISTENT 80% SCREEN

Apply the same normal-transformer screen—unchanged for customer class, income, community, or geography.

06 ENGINEERING OUTPUT

The result is an engineering-reviewed screen—not an automatic extrapolation.

EVOLVING TEN-YEAR PLAN BEYOND TRADITIONAL CAPACITY PLANNING

CURRENT

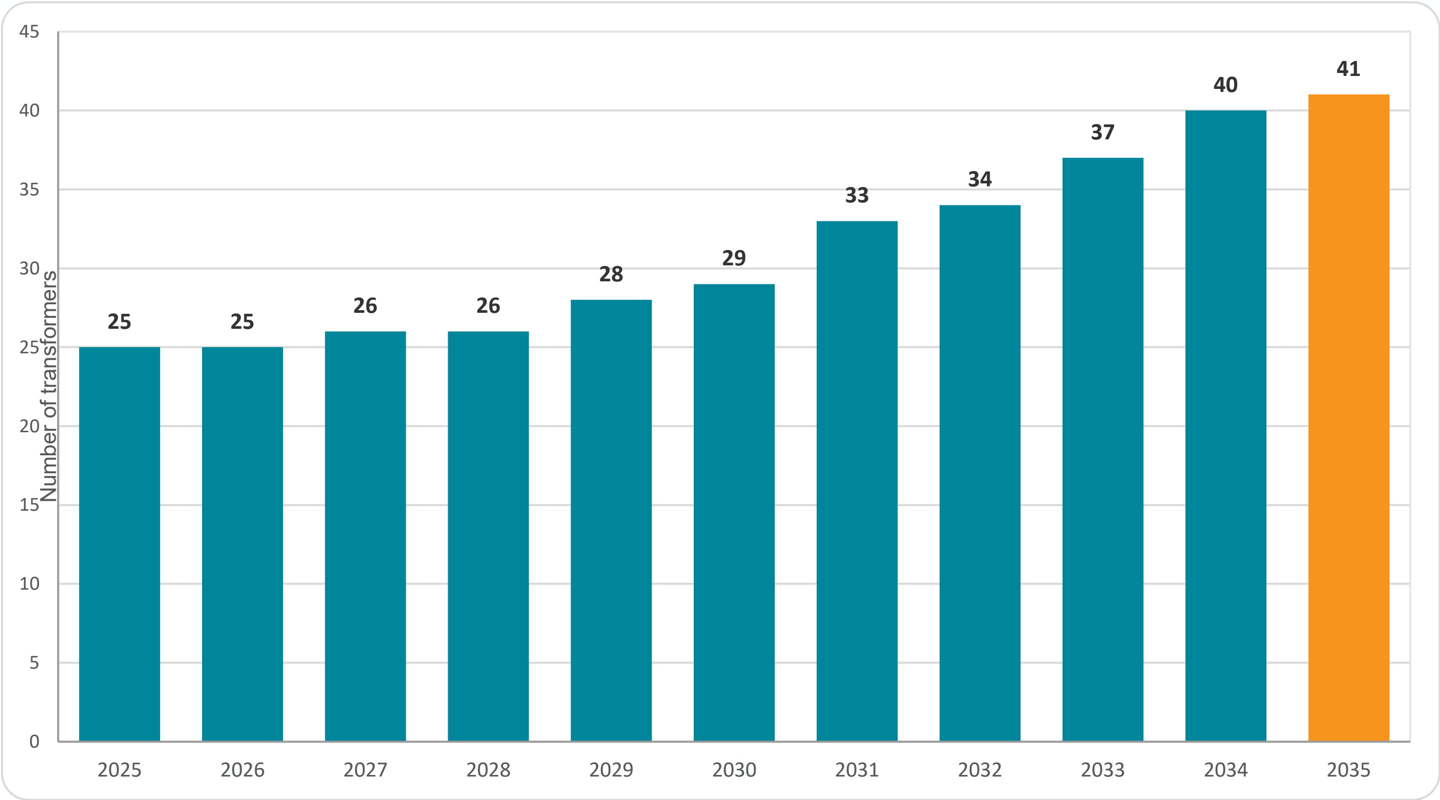
- Historical load growth, current loading, and known new-load interconnections.
- High-level N-1 transformer and transformer-level hosting-capacity indicators.
- Economic-development projects when demand, timing, and serving facilities are defined.

Vs.

DEVELOPING

- More detailed feeder-level information and fuller electrification forecasting.
- Improved treatment of EVs, building electrification, rooftop PV, storage, demand response, AMI, automation, and grid-modernization data.

TRANSFORMERS ABOVE THE 80% PLANNING CRITERION INCREASE FROM 25 TO 41



RECONFIGURATION STUDY

01 **CONCERN IDENTIFIED**

Begins after the Ten-Year Plan, Substation Outage Review, or another planning review identifies a concern.

02 **TEST RECONFIGURATION OPTIONS**

Feeder ties • Switching • Transfers • Phase balancing • Targeted conductor or cable upgrades
Voltage devices • Protection • N-1 restoration

PRACTICAL + DURABLE SOLUTION?

YES

OPERATING PLAN / TARGETED IMPROVEMENT

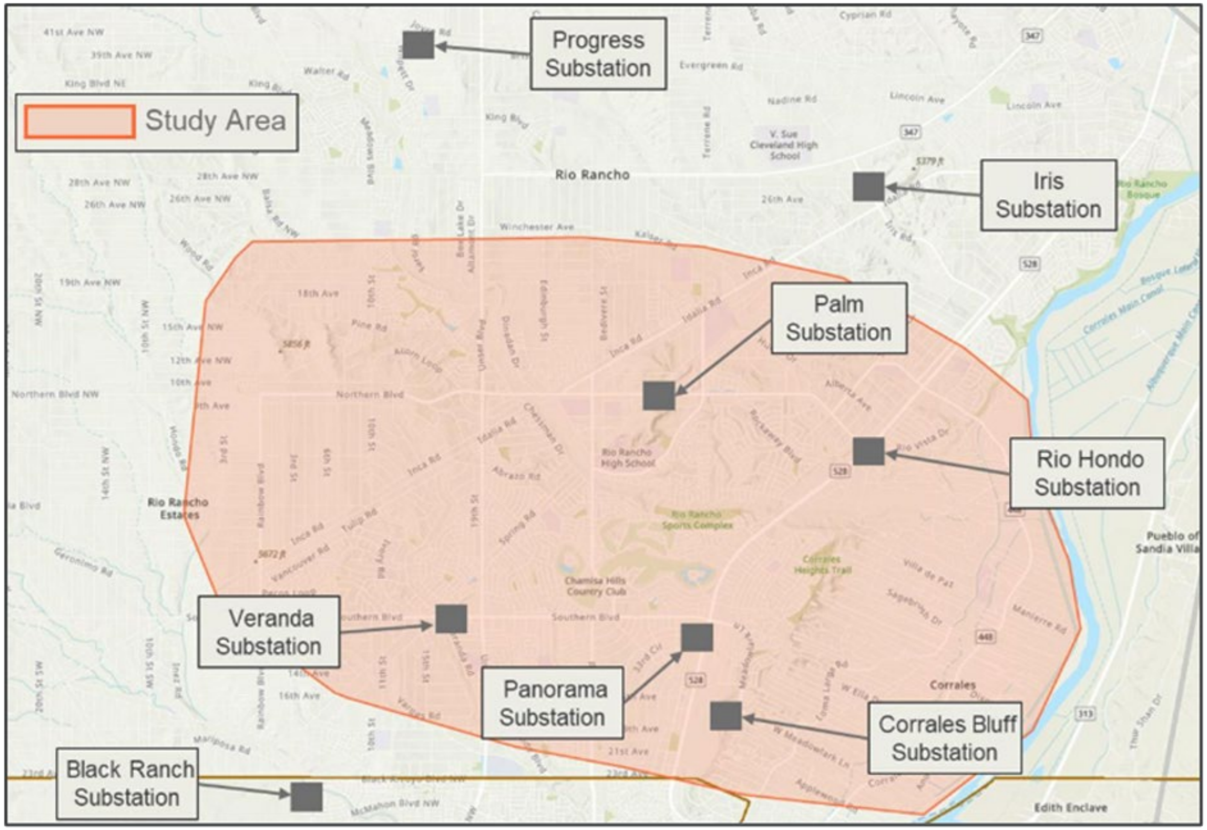
PNM may document the practical, durable solution.

NO

DETAILED AREA STUDY

If reconfiguration is insufficient, the concern proceeds.

EXAMPLE DETAILED AREA STUDY GEOGRAPHY



THE TYP IDENTIFIES THE ISSUE; THE AREA STUDY DEFINES THE SOLUTION

TEN-YEAR PLAN
ISSUE

SCREEN + PRIORITIZE

1. **DIVISION + CLUSTER SCREEN**

   Forecasts and high-level contingency and hosting capacity indicators

2. **NO FEEDER POWER-FLOW MODEL**

   Supports prioritization and potential timing

ADVANCE

DETAILED AREA STUDY
SOLUTION

MODEL + DEFINE

- ✓ **Feeder/Substation Power-Flow Models**
- ✓ Thermal, voltage, protection, switching, contingency + sensitivities
- ✓ Compares alternatives and supports transition to construction, design, cost refinement + regulatory review

BOTTOM LINE | **The TYP alone is not sufficient for major-project approval.**

MONTAÑO–CLAREMONT: COMPARING THREE CAPACITY ALTERNATIVES

PLANNING TOOLS BECOME MORE DETAILED AS THE ISSUE ADVANCES

1 SCREEN
SYSTEM NEED

TYP workbook + SCADA

History, forecasts, cluster screens, contingencies, and high-level hosting indicators.

2 MAP
NETWORK CONTEXT

GIS / Utility Network + Electric Web Viewer

Topology, assets, connectivity, and equipment data.

3 ENGINEER
DETAILED MODELS

Synergi Electric — feeder power flow, voltage, thermal, contingency + hosting capacity.

CYMCAP — underground cable ampacity + emergency evaluation.

EPRI PTLoad — transformer ratings using IEEE C57.91-2011.

4 PRIORITIZE
DELIVERY DECISIONS

AOP + budgeting tools

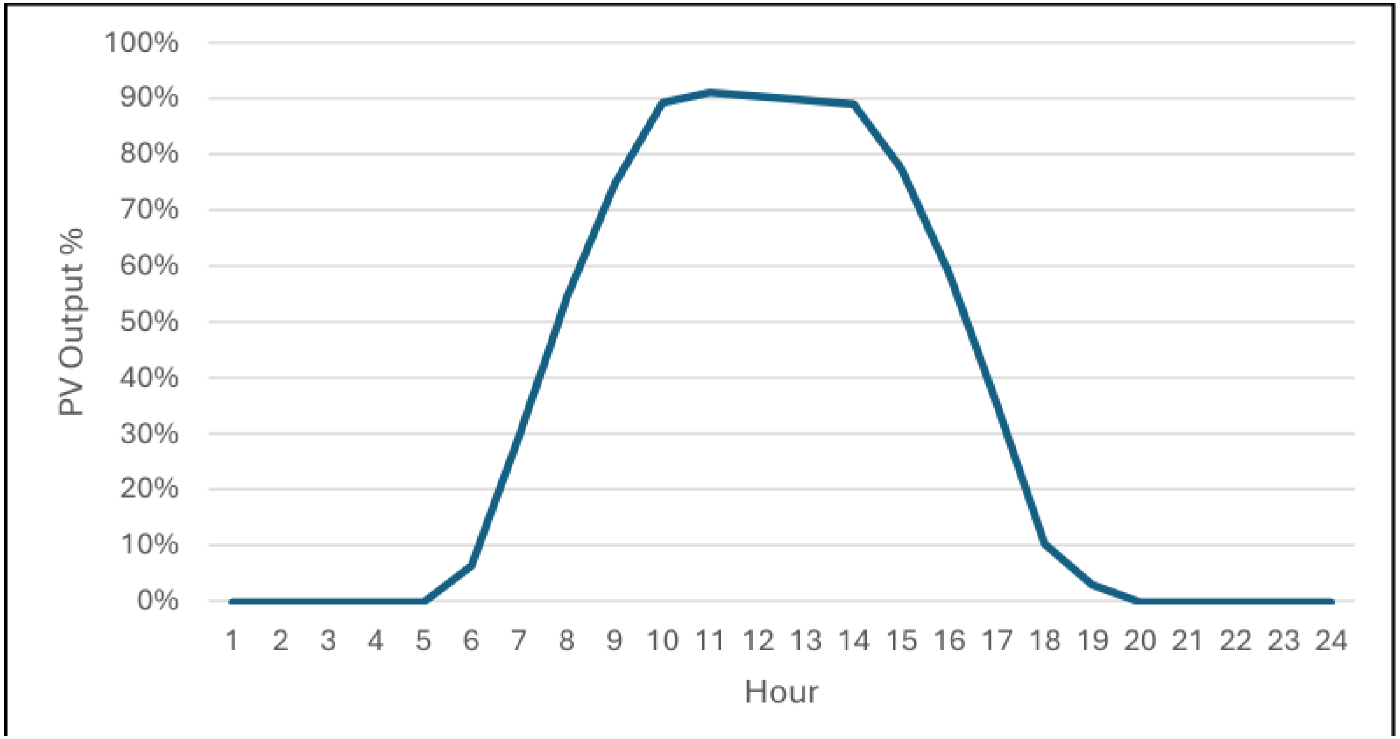
Timing, budget, prioritization, and benefit-cost coordination after a need is identified.

More detail, specificity, and decision confidence →

10 Minute Break

Load-Altering Considerations

TIME OF DAY CHANGES THE PLANNING QUESTION



LOAD-SHAPING RESOURCES CAN RELIEVE CONSTRAINTS—OR CREATE NEW ONES

	CAN RELIEVE CONSTRAINTS	CAN CREATE NEW ONES / DEPEND ON CONDITIONS
DR — **DEMAND RESPONSE / DSM**	RELIEF / CURRENT VALUE PNM's current implementation is systemwide.	NEW CONSTRAINT / CONDITION Locational targeting is developing.
EV — **ELECTRIFICATION**	RELIEF / CURRENT VALUE Managed charging can shift load.	NEW CONSTRAINT / CONDITION Concentrated load can create new feeder constraints.
PV — **ROOFTOP PV**	RELIEF / CURRENT VALUE Reduces daylight net load.	NEW CONSTRAINT / CONDITION Can increase reverse-flow, voltage, thermal, and protection risk.
BESS — **BATTERY ENERGY STORAGE**	VALUE Value is highly situation-specific.	CONDITIONS THAT DETERMINE VALUE Depends on siting, control, communications, availability, interconnection, and cost.

A NON-WIRES ALTERNATIVE MUST WORK AT THE CONSTRAINED PLACE AND HOUR

POTENTIAL PORTFOLIO

The resource can be a combination of flexible load, grid controls, and DER.

LOAD FLEXIBILITY

Targeted demand response • efficiency • managed EV charging

GRID + DER CONTROL

Storage • DERMS or VPPs • targeted DER or microgrids

NETWORK OPERATIONS

Voltage optimization • reconfiguration • automation

FIT

RIGHT PLACE
RIGHT HOUR

MUST PASS EVERY TEST

- ✓ Available at the exact constrained location and during the relevant hours
- ✓ Comparable reliability, resilience, operating control, and customer impact
- ✓ Satisfies contingency and voltage performance
- ✓ Communications and cybersecurity are feasible
- ✓ Cost and implementation timeline are competitive with a traditional solution

Hosting Capacity Analysis

RULE 568 PHASE 1 STUDY ESTABLISHED THE INITIAL METHOD

Completed May 22, 2024 • Phase 1 evaluated feeder conditions under three scenarios

30 FEEDERS

18 SATURATED	6 HIGH-PV	6 LOW-PV

THREE SCENARIOS

1. **Base case**
2. **System improvements**
3. **Non-export inverter sensitivity**

SCREENING LOGIC

1. **Minimum daylight load**
   Local demand may be low while PV output is high.
2. **PV-saturation screen**
   Aggregate DER exceeds 90% of feeder rating.
3. **Reverse-flow check**
   The fuller evaluation also tests minimum daytime load.

RESULT: Supports planning and supplemental review — it does not approve a specific interconnection.

HIGH-PV FEEDERS REQUIRE MORE FREQUENT HOSTING-CAPACITY REVIEWS

0–30% PV	30–60% PV	60–90% PV	≥90% PV	Purpose
No routine refresh	≈24 months	≈12 months	≈6 months	Prioritize high-PV feeders

High-PV feeders require more frequent review because hosting capacity changes more quickly as DER, load, and operating conditions change.

Rule 568 Hosting Capacity refresh cadence depends on model/data readiness, resources, automation, and regulatory direction.

PHASE 2 STUDY EVALUATED MULTIPLE IMPROVEMENT OPTIONS

Feeder Upgrades	Feeder Upgrades & BESS Charging at 2 MVA	Feeder Upgrades & BESS Charging at 6 MVA	Dedicated Feeder Buildout

Each option must be evaluated for engineering viability, cost, operating requirements, and the hosting capacity it unlocks.

RULE 568 STUDY PHASES 2 AND 3 ARE COMPLETE

PHASE 2 From study to system-wide hosting readiness **COMPLETE**

18	13	11	ALL
SATURATED FEEDERS	**PENDING CUSTOMERS**	**COULD INTERCONNECT**	**PNM FEEDERS**
studied in Phase 2	identified on those feeders	while 2 needed improvements	could host customer-sited installations by July 2026

PHASE 3 **27** FEEDERS = **18 original** + **9 Community Solar**

All nine reduced hosting capacity.

⚠ **Reverse-flow conditions require Rule 568 supplemental review.**

CURRENT INTERIM MAPS AND AUTOMATED HCA HAVE DIFFERENT ROLES

CURRENT INTERIM MAP

BROAD VISIBILITY NOW

- ✓ **Interconnection map for all feeders**
- ✓ Updated at least quarterly

MAP STATUS

- **No hosting capacity** (red)
- **Reverse flow + available capacity; supplemental review** (yellow)

AUTOMATED HCA FOUNDATION

DEEPER LINE-SECTION DETAIL

- ✓ Detailed Power-Flow analysis on 27 high-PV feeders from Phase 3 study
- ✓ Utility Network + Synergi–Cascade linkage implemented June 1, 2026; validation continues
- ✓ Automated analysis requires additional links to equipment, protection, load, DER, inverter, BESS data

BROAD MAP → AUTOMATED HCA

AUTOMATED LINE-SECTION HCA IS TARGETED BEFORE END-2028

TARGET **BEFORE END-2028**

1 MODEL BUILD

Automate and optimize the Synergi feeder model build.

2 FORECAST + SCENARIOS

Incorporate future feeder-load forecasts and scenario conditions.

3 PUBLIC UPDATES

Automate HCA updates with effective dates, methods, ranges, and limitations for a public-facing platform.

DEPENDENCIES

- Model + equipment
- DER + load data
- Cybersecurity
- Validation
- Resources
- Regulatory direction

PLANNING GUIDANCE ONLY | Not interconnection approval or a substitute for project-specific review.

Vision for the Future
An Evolving System

PNM'S VISION FOR THE FUTURE

Maintain a **safe, reliable, and resilient** distribution system while managing increasingly dynamic power flows

Transform the grid to support New Mexico's **carbon-free energy future** and meet the State's policy goals

Combine traditional infrastructure investments and grid modernization technologies for an **intelligent, flexible, and data-driven network** capable of integrating DERs, electrification and economic growth

Ensure operational efficiency, **affordability, and customer value**

IMPLEMENTING PNM'S VISION FOR THE FUTURE

Mitigating System Risk - High Fire Risk Area (HFRA)	• Targeted Design and Equipment Standards - Open-wire secondary and Live-Front Replacements, System Hardening, Vegetation Mgmt, Monitoring, Lightning Mitigation, PSPS Program
Modernizing the Grid	• AMI, Communications, Distribution Automation, ADMS, DERMS, Integrated Volt/VAR, FLISR, and improved data models
Improving Reliability Metrics and System Performance	• Legacy and Aging Infrastructure Upgrades - Equipment, Replacements (Structures, Cables, Protection, etc.), Redundancy (Looping), and Design and Equipment Standardization
Efficiently and Safely Enabling Resources Interconnections	• Forecasting, Modeling, Hosting Capacity Study Automation
Supporting Growth – EV, Electrification, Economic Development	• Future Proof Design Standards, Non-wires alternatives, Substation Expansions, and New Feeders and Feeder Rebuilds, SB 170 Investment

WILDFIRE TECHNOLOGY AND FIVE-YEAR PRIORITIES

Annual wildfire planning — includes the Wildfire Mitigation Plan, Public Safety Power Shutoff Plan, and expense reporting to the NMPRC.

High Fire Risk Areas — receive targeted grid investment, vegetation management, easement width, asset-health remediation, and hardware upgrades.

Public Safety Power Shutoff — supports proactive de-energization during high modeled wildfire risk and layered customer communications.

Program delivery — overlapping two-year engineering/design and construction cycles maintain executable scope.

Reliability and redundancy — include open-wire secondary upgrades, underground looping, switchgear modernization, and smart-device replacement.

System hardening — includes lightning mitigation, feeder rebuilds, and distribution-relay modernization.

WILDFIRE TECHNOLOGY AND FIVE-YEAR PRIORITIES

Four-part strategy — ignition prevention and hardening, risk-informed mitigation, operational resilience, and community engagement.

Field infrastructure — prioritized telecommunications, SCADA-enabled devices, segmentation, reclosers, fuses, covered wire, and strategic undergrounding.

Situational awareness — line sensors, cameras, 66 weather stations, LiDAR, satellite, drone, and 3D point-cloud data.

Drone capability — an in-house program with beyond-visual-line-of-sight inspection and event-support capability.

Data and decisions — governance, asset-health systems, dashboards, and AI/ML with human validation, ultimately supported by ADMS.

Intended outcomes — reduce ignition risk, reduced PSPS impacts, faster re-energization, and 24/7 system awareness.

GRID MODERNIZATION PLAN SUMMARY

Approved program — six-year, $344 million Grid Modernization plan approved in 2024.

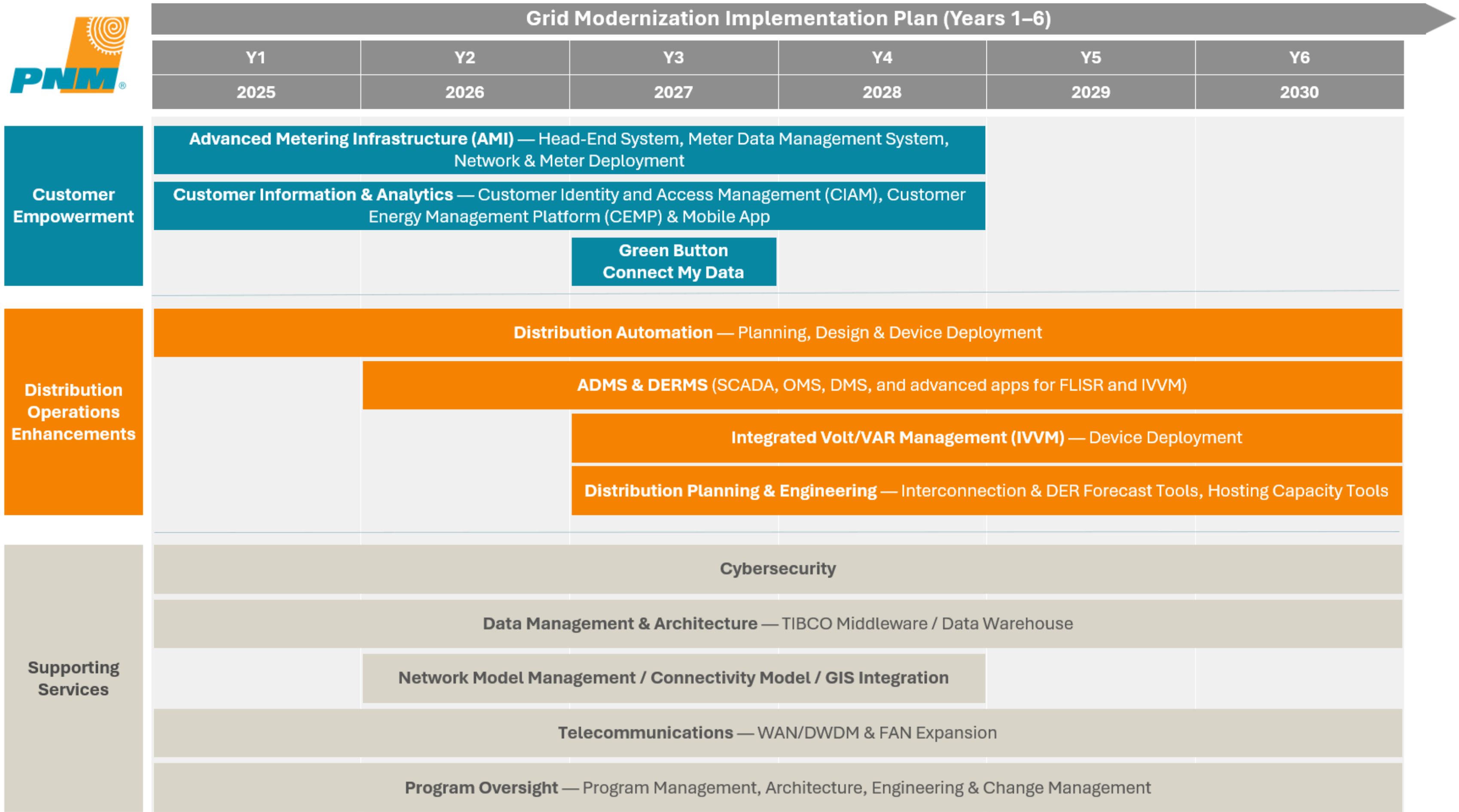
Technology portfolio — AMI, communications, DA, ADMS, DERMS, Integrated Volt/VAR, FLISR, and improved data models.

Planning value — improves forecasts, area studies, hosting capacity, contingencies, DER integration, and non-wires evaluation.

Operational value — links engineering assumptions with more current system conditions and remote control.

Implementation — phased work runs through 2030, with 2026 representing year two of the plan.

GRID MODERNIZATION IMPLEMENTATION PLAN, 2025–2030



IMPROVING RELIABILITY METRICS AND SYSTEM PERFORMANCE

Replace poles and related assets based on condition and develops a cyclical inspection program

TRIGGER	INSPECT	ACTION	INCLUDE	BENEFIT
Pole age / size / condition	Cyclical pole program	Replace structures	Attached assets as needed	Lower failure risk

Distribution Looping (Redundant Service)

TRIGGER	EXISTING	ACTION	RESPONSE	BENEFIT
Problem radial feeder	No alternate source	Add loop + conduit	Switch around a fault	Faster restoration

Smart Device Replacement and Upgrade

TRIGGER	EXISTING	UPGRADE	CONNECT	BENEFIT
Obsolete protection	Manual / limited control	Intelligent reclosers + switches	SCADA to DOC	Faster isolation + better data

IMPROVING RELIABILITY METRICS AND SYSTEM PERFORMANCE

Distribution Relay Replacements

TRIGGER	ACTION	DESIGN	FOCUS	BENEFIT
Obsolete relays	Microprocessor relays	Redundant + maintainable	HFRA priority	Faster fault isolation

Cable Replacement Program

TRIGGER	EXISTING	PLAN	ACTION	BENEFIT
Aging underground cable	Rising failure risk	Inspect + assess + design	Replace before failure	Long-term reliability

Feeder Rebuilds

TRIGGER	NEED	ACTION	ADD	BENEFIT
3–5 year performance	Aging / capacity / reliability	Poles + conductors + getaways	Protection + fiber	Current-standard backbone

AUTOMATED HOSTING CAPACITY ROADMAP

Feeders identified as at PV saturation
Heat-map results for FDR at PV saturation - transparent feeder-level thermal, voltage, and line-section constraints evaluation

→

GIS / Utility Network upgrade
Improve quality of dist topology and asset data to build and validate models – Foundational next stage automation.

→

Synergi and Cascade linkage
Incorporates voltage reg settings and device data into Synergi models – with linkages to asset databases

→

DER data by type
Allows the model to distinguish rooftop PV, community solar, large PV, BESS, microgrids, and other DER. Necessary for feeder-level HCA.

Inverter operation and export modeling
Improves evaluation of non- and limited-export, Volt/VAR – key for accurate net-load, minimum-daylight-load, HCA.

→

TIIR Modeling
Interconnection and operational analysis affecting DER operation for next gen HCA modeling.

→

Profiler load and generation data linkage
Improves modeling of min daylight load, large PV output, coincident cust load, and supports

→

Synergi Data-lake automated HCA pilot
Tests automation on selected feeders at capacity or otherwise constrained.
Verification before feeder-by-feeder rollout.

Refresh Cadence by PV Penetration
Prioritizes higher-PV feeders for more frequent review - focuses automation and engineering review where needed most.

→

Public maps or public-facing results
Improves transparency -
Public-facing once data quality, security, and regulatory review are complete.

→

Two- to three-year public-facing map direction
Provides an indicative planning horizon for public-facing HCA -dependent on model readiness, data, cybersecurity, stakeholder and regulatory direction.

SUPPORTING GROWTH – EV, ELECTRIFICATION, ECONOMIC DEVELOPMENT

Future Proof Design Standards

- Expandable Substation Footprint, Sectionalization

Non-wires alternatives

- Distribution sited BESS

Expansions and Rebuilds

- Future Substation Land and Siting, Expansion of Existing Subs, New and Rebuilt Feeder Capacity

SB 170 Investment

- Proactive West Point 40 and Mesa del Sol Expansion for Economic Development Load

PNM Distribution System Investment and Benefit Cost Prioritization

HISTORICAL DISTRIBUTION CAPITAL AND O&M

Capital Category	2023 Historical Capital Spend	2024 Historical Capital Spend	2025 Historical Capital Spend	2023-25 Historical Capital Spend
Asset management	$ 141,629,748	$ 114,231,711	$ 155,839,166	$ 411,700,624
Customer programs	$ 103,892,428	$ 66,659,684	$ 98,960,271	$ 269,512,383
Economic development	$ 12,771	$ 1	$ 10,000,354	$ 10,013,126
Grid Mod	$ -	$ 5,359,104	$ 30,817,750	$ 36,176,854
Distribution planning	$ 41,945,781	$ 53,281,577	$ 19,321,638	$ 114,548,996
Other	$ (232,429)	$ 922,865	$ 4,494,395	$ 5,184,831
	$ 287,248,298	**$ 240,454,942**	**$ 319,433,575**	**$ 847,136,815**

	2023 Historical O&M Spend	2024 Historical O&M Spend	2025 Historical O&M Spend	2023-25 Historical O&M Spend
Historical O&M	**$ 33,269,256**	**$ 32,871,612**	**$ 35,860,363**	**$ 102,001,231**

COST DRIVERS, RECOVERY, AND GMS DELINEATION

DSP Filing — the DSP is informational; PNM is not requesting cost recovery in this filing.

Future consideration — PNM is evaluating a request for future Distribution System Plan approval and associated Distribution System Rate Rider; none is proposed or being requested here.

Cost drivers — load growth, economic development, electrification, DER, aging assets, modernization, emergent conditions, and resilience.

Grid Modernization Systems — grid mod rider for grid mod communications, monitoring, automation, control, cybersecurity, and data management.

Ordinary-course 440 Filing distribution — capacity, reliability, safety, wildfire mitigation, and asset replacement.

POTENTIAL FEDERAL FUNDING

- **Application** — PNM applied in 2024 under DOE GRIP Topic Area 2 for a VPP Enablement project.
- **Proposed DOE funding** — $35.6 million across VPP software, a front-of-meter battery, behind-the-meter devices, integration, and aggregator services.
- **Five workstreams** — strategy and design, program development, system implementation, customer enrollment and devices, and Grid Modernization.
- **System coordination** — anticipated with DERMS, FLISR, and Integrated Volt/VAR capabilities as available.
- **Current status** — DOE negotiations are incomplete; there is no executed award, and final funding, scope, and schedule may change.

No state funding identified at this time

COPPERLEAF SUPPORTS CONSISTENT VALUE COMPARISON

- Copperleaf software platform supports consistent value models, benefit scoring, prioritization, and portfolio comparison.
- Used widely for investment decision-making in the utility industry.
- Compares both traditional investments, which remain essential for physical capacity, safety, reliability, and asset condition, with other investments such as Grid Modernization.
- Continuously improving data and value comparison ensures optimal project scope, timing, location, and investment sequencing.
- Operating strategies, storage, demand response, managed charging, and automation supplement traditional work where feasible and demonstrate customer value.

Action Plan

ACTION PLAN

01 **Prioritized List of Investments, Expenditures, And Activities**
Action: PNM will pursue the following distribution investments in the near-term to ensure on-going distribution system reliability. PNM will continuously monitor and make any adjustments to priority as system or customer needs change.

02 **Automated Hosting Capacity Capability**
Action: PNM will complete its Grid Mod effort to automate its hosting capacity analysis and ensure that analysis is provided on a public-facing platform for use by customers and other stakeholders. PNM will continue to complete the necessary foundational data and software required elements in accordance with the details outlined in PNM's Grid Modernization Plan.

03 **DOE Grant Projects (Pilot)**
Action: PNM will continue to pursue finalization of the DOE Grant to support a VPP pilot on PNM's system. Add a topic for the presentation

04 **Strategic Partnerships**
Action: PNM will continue to collaborate with the following strategic partners on R&D related types of projects and/or studies, in alignment with the investment and system prioritizations noted.

05 **Future Distribution System Plan Approaches and Funding Mechanisms**
Action: PNM will explore its approach to future DSPs including opportunities to improve the reporting and regulatory approaches such as seeking future NMPRC approvals for such plan(s). PNM will also explore the concept of a Distribution System Rate Rider. Each concept will be considered in the context of customer service benefits or advantages when determining a proposed path forward.

Key DSP Metrics

RELIABILITY AND GROWTH

Reliability Metrics

These measures demonstrate whether the distribution system is providing dependable electric service.

SAIDI (System Average Interruption Duration Index): Average outage duration per customer.

SAIFI (System Average Interruption Frequency Index): Average number of outages per customer.

CAIDI (Customer Average Interruption Duration Index): Average restoration time per outage.

Circuit reliability performance: Number of circuits performing below established reliability targets.

Measure of Success: Reduction in outage frequency and duration over time, particularly on poor performing circuits.

System Capacity and Load Growth Metrics

Peak loading of substations and feeders.

Number of substations operating above defined planning thresholds (e.g., 80% or 90% of firm normal/emergency capacity).

Number of overloaded distribution feeders.

Economic development interconnection requests accommodated.

Measure of Success: Fewer constrained facilities and timely accommodation of customer growth without degradation in reliability.

HOSTING, ASSET HEALTH, AND CUSTOMER EXPERIENCE

DER and Hosting Capacity Metrics
Total distributed generation interconnected (MW).
Annual distributed generation applications received and processed.
Average interconnection processing time.
Hosting capacity by feeder (available after 2028).
Percentage of feeders with published hosting capacity information.
Energy storage interconnected to the distribution system (MW/MWh).
Measure of Success: Increased hosting capacity, reduced interconnection timelines, and fewer customer interconnection constraints.
Asset Health and Aging Infrastructure Metrics
Condition assessment scores for major asset classes.
Number of open-wire secondary and other hazardous conditions corrected.
Measure of Success: Reduction in high-risk aging infrastructure and asset failure rates.
Customer Experience Metrics
Customer satisfaction survey results.
New service connection timelines.
Interconnection application processing times.
Measure of Success: Improved customer satisfaction and more timely service delivery.

Thank You

Questions and Discussion

Written comments due: August 31, 2026
PNM response: September 11, 2026
Second public meeting: September 21, 2026
Email: distributionsystemplan@pnm.com
Website: pnm.com/distributionsystemplan