2025 Natural Gas Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Wednesday, April 24, 2024
Virtual Meeting

Topic	Time (PTZ)	Staff
Agenda/Meeting Guidelines	10:30	Tom Pardee
Action Items	10:40	Tom Pardee
Modeling/Assumptions Overview	11:00	Tom Pardee
CROME High Level Overview	11:25	Michael Brutocao

Microsoft Teams meeting

Join on your computer, mobile app or room device

Click here to join the meeting

Meeting ID: 285 938 629 442

Passcode: 8TysAy

Download Teams | Join on the web

Or call in (audio only)

+1 509-931-1514,,325846108# United States, Spokane

Phone Conference ID: 325 846 108#

Find a local number | Reset PIN

Learn More | Meeting options

2023 Gas IRP Action Items

Summary of Acknowledgement

- Idaho – Acknowledged (November 1, 2023)
- Oregon – Pending short term acknowledgment
- Washington – No word on acknowledgment

Avista – 2023 Gas IRP Actions

1. ETO identified 546,000 therms in the 2023 IRP verses 427,000 therms of planned savings in the 2023 ETO Budget and Action Plan. Avista will work with ETO to meet IRP gross savings target of 568,000 therms in 2024.
2. New program offered by ETO for interruptible customers in 2023 to save 15,000 therms.
3. Engage Oregon stakeholders to explore additional new offerings for interruptible and low-income customers to work towards identified savings of 375,000 therms in 2024.
4. In Washington purchase allowances or offsets for compliance to the Climate Commitment Act for years 2023, 2024, 2025 and 2026 to comply with emissions reduction targets.
5. Begin to offer a Washington transport customer EE program by 2024 with the goal of saving 35,000 therms
6. Explore methods for using Non-Energy Impact (NEI) values in future IRP analysis to account for social costs in Washington to ensure equitable outcomes.
7. Explore using end use modeling techniques for forecasting customer demand.
8. Consider contracting with an outside entity to help value supply side resource options such as synthetic methane, renewable natural gas, carbon capture, and green hydrogen.
9. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high-pressure distribution line or city gate station in order to deliver safe and reliable services to our customers, the Company is not precluded from doing such work. Examples of these necessary capital investments include the following:
   - Natural gas infrastructure investment not included as discrete projects in IRP
     - Consistent with the preceding update, these could include system investment to respond to mandates, safety needs, and/or maintenance of system associated with reliability
       - Including, but not limited to Aldyl A replacement, capacity reinforcements, cathodic protection, isolated steel replacement, etc.
     - Anticipated PHMSA guidance or rules related to 49 CFR Part §192 that will likely require additional capital to comply
       - Officials from both PHMSA and the AGA have indicated it is not prudent for operators to wait for the federal rules to become final before improving their systems to address these expected rules.
     - Other special contract projects not known at the time the IRP was published
   - Other non-IRP investments common to all jurisdictions that are ongoing, for example:
     - Enterprise technology projects & programs
     - Corporate facilities capital maintenance and improvements

IPUC - Recommendations

No.	Recommendation	2025 IRP
1	Staff recommends the Company's 2023 Natural Gas IRP be acknowledged and accepted for filing contingent on the Company submitting a compliance filing with an updated DSM Avoided Cost table that does not include a National Carbon Tax starting in 2030; and	✓
2	Staff recommends that the Commission require the Company to include updates on PLEXOS® implementation, model validation, and enhancements in its semi-annual Natural Gas Updates with the Commission.	✓

OPUC - Recommendations

No.	Recommendation	2025 IRP
1	Do not acknowledge 8.64 million therms of RNG in 2023.	Removed
2	For the IRP Update the Company should update the load forecast with a downscaling methodology using Multivariate Adaptive Constructed Analogs as employed by Oregon State University's Institute of Natural Resources.	✓
3	Regardless of the analytical approach taken to create the PRS, future IRPs should include alternative resource portfolios that represent different utility decisions.	✓
4	Future IRPs should include stress testing of the RPS and alternative resource portfolios and provide metrics comparing the severity and variability of risk in alternative portfolios.	✓
5	In the next IRP should include modeling of all relevant distribution system costs and capacity costs, including additional projects that would be needed in high load scenarios as well as costs that would not be incurred in lower load scenarios.	✓
6	Avista work with the TAC to develop additional scenarios and sensitivities for the next IRP, including for example: greater price variation for low carbon resources, high cost for low carbon resources, omission of any highly uncertain resource, or utilization of only existing resources.	✓
7	To start to understand baseline electrification occurring naturally, Staff recommends Avista use advanced metering infrastructure data and Form 10Q data to capture customer behavior as discussed in Section 6.3. At the IRP update, Avista should present that information in the attached worksheet templates (Attachment B).	✓
8	In the IRP update, Avista should clarify whether it has precedent agreements or other contracts for the GTN Xpress. If so, Avista should explain its capacity on this new expansion.	No Agreements with GTN Xpress

OPUC Staff - Expectations

No.	Expectation	2025 IRP
1	At a TAC meeting for the next IRP, Avista should provide an estimate of the capacity in MW of electrolyzers, renewable generation, and methanation equipment needed in each year to include synthetic methane in the Oregon PRS. The Company should also provide the cost and quantity of CO2 needed in each year in key portfolios to support synthetic methane production. Lastly, the Company should seek alignment from participants regarding price and availability forecasts and approaches for modeling risk.	✓
2	Avista should provide an RNG procurement update in its next IRP Update including a comparison of projected and actual procurement; RNG prices secured; a description of how the Company has leveraged other carbon markets to reduce RNG costs; and how the Company is applying the environmental attributes of the RNG procured to CPP compliance. Further, where actuals volumes of RNG used for CPP compliance are less than those projected, the Company should describe its plan to address those compliance deficiencies.	✓
3	The next IRP should show a load forecast that reflects GCM trends by downscaling the model appropriately onto the Company's Oregon service territory.	✓
4	For the next IRP, engage the TAC regarding the GCM model downscaling methodology proposed for the next IRP.	✓
5	For the next IRP, include a scenario of future weather informed by the RCP 6.0 model.	✓
6	For the next IRP, include a scenario of no future customer growth beyond 2027.	✓
7	Continue to work with TAC members on how to model customer growth impacts from HB 3409 and the potential for further Oregon electrification policies reflecting those in place in Washington.	✓
8	For the next IRP, update its customer growth modeling to reflect the line extension allowance decision flowing from Docket No. UG 461.	✓
9	For the next IRP, update its application of IRA credits to all applicable resources, including electrification resources.	✓
10	Scenarios and sensitivities developed for the next IRP should include complex possible futures that capture plausible sources of risk due to uncertainty; Avista should explore its resource portfolios against these scenarios. Avista should run stochastic analysis for price and demand assumptions consistent within scenarios and report risk severity metrics for each scenario.	✓
11	Avista should engage stakeholders and the TAC to seek input on any additional modeling methodologies or techniques to better capture risk.	✓
12	Avista should work with Staff and the TAC to investigate PLEXOS' ability to integrate risk aversion.	✓
13	In its next IRP, Avista include a qualitative risk matrix in the next IRP that consolidates risk assessment for each resource in one chart and provides a narrative risk assessment about each resource option's potential for negative outcomes due to uncertainty.	✓

OPUC Staff - Expectations

No.	Expectation	2025 IRP
14	The Company should conduct a review, comparing projections from this IRP to actuals of their resource assumptions, quantitative least-cost/least risk predictions, and forecasts.	✓
15	Avista should work with the TAC to develop electrification modeling that reflects refined customer attrition assumptions.	✓
16	The next IRP include electrification modeling assumptions that decrease capacity costs, distribution system costs, and other appropriate expenses corresponding with reduced demand from electrification.	Discussion
17	Future IRPs should include a scenario with significantly increased residential heat pump adoption and the corresponding shift in winter load from the gas system to the electric system.	✓
18	Avista should work with the TAC to more fully explore and model the potential of dual fuel heat pumps in the next IRP, for example by ensuring that the use of some dual fuel heat pumps is represented in Monte Carlo risk analysis.	✓
19	Before the next IRP, Staff expects Avista to work with the TAC to consider Staff's revised Electrification Incentive Strategy (see Attachment A).	Discussion
20	Staff expects Avista to work with the TAC to identify a PacifiCorp IRP scenario reflecting electrification that Avista might use to generate a load forecast for its next IRP. Before the next IRP, Avista should work with PacifiCorp to collect the load forecasts used in planning that most closely reflects a building electrification scenario for the overlapping territories. With these load forecast results, Avista should discuss with PacifiCorp supporting commentary regarding supply-side and demand-side resource impacts, rate impacts, and associated GHG emissions with each scenario/portfolio. Avista should discuss with the TAC the extent to which the Company might be able to model the equivalent in its next IRP.	TBD - Need data from Electric Utilities
21	Before the next IRP, Staff expects Avista to host electrification workshops, addressing the issues listed in Section 6.4 to support a discussion on a proactive resource strategy.	✓
22	Avista should update its distribution system planning practices and its future IRP processes as outlined in Attachment C.	✓
23	Avista should apply distribution system planning practices as outlined in Attachment C to the Sutherlin project and should continue to explore targeted electrification to offset demand at the Sutherlin gate station.	✓
24	For future IRPs, the Company should discuss in a TAC meeting how Avista envisions avoided costs determinations aligning with resource portfolios made up of higher priced fuels and declining natural gas, and how that will be reflected in its next IRP.	✓
25	In the next IRP, Avista should include a workpaper of the fixed fees paid on each unit of capacity under contract and provide an update on potential or existing plans to retire firm capacity contracts.	✓

AVISTA

WUTC Staff - Recommendations

Topic	No.	Recommendations
Equity	1	Review the Cascade Natural Gas general rate case final order with the TAC and the EAG together, consider how the core tenets of energy justice apply to Avista's planning processes, and prepare to implement the order's equity framework. Dedicate time in the work plan for this topic.
	2	Staff recommends that Avista consult with its equity advisory group to develop equity criteria for the siting of distribution projects and reinforcements.
Changing Regulatory and Incentive Landscape	3	Include full accounting of the IRA in the 2025 IRP and provide sufficient time in the work plan for discussion within advisory groups.
	4	Work with the Department of Ecology, Staff, and advisory groups, to discuss the implication of this "cap" and how it is likely to be achieved.
	5	Provide a robust discussion of the "invest" portion of the "cap-and- invest" and discussion of the downstream impacts of CCA investments.
	6	Account for and provide a narrative discussion regarding electrification driven by the CCA and discuss the CCA within its advisory group early in the IRP development process.
Climate change impacts	7	Adopt representative concentration pathway (RCP) 8.5.
	8	For greater clarity, for tables like Table 2.3, replace with time series graphs with appropriate box and whisker plots.
	9	Revisit and update the winter peaking climate data and methodology as evidence and climate models improve.
Load forecasting	10	Where the specifics of future energy codes are unknown, project a forecast trend that accords with statutory goals and mandates.
	11	Develop a building stock attrition rate to represent the loss of customers due to buildings being demolished, remodeled without gas service due to incompatible use cases, or otherwise leaving gas service unrelated to changes in the price competitiveness of gas services.
	12	Adopt future building codes that are already imbedded in law as foundational assumptions for the primary demand forecast and not as a scenario.
	13	Analyze risks to customers and the distributional effects through the lens of equity, energy justice, and access to energy efficiency and electrification resources.
	14	Dynamically model the anticipated comparative costs between its natural gas services and electric utility services into the future as well as the interplay of customers, by class, responding to changing comparative cost.
	15	Incorporate the distributional analysis discussed below into the comparative cost analysis.

WUTC Staff - Recommendations

Topic	No.	Recommendations
Demand-side Potential Assessments	16	Continue to refine the methods and approach of leveraging potential assessments for achieving equitable outcomes.
	17	Segment customers with different levels of gas to electric conversion costs rather than modifying costs only by scenario.
	18	Consider audits of specific transportation customer sites to better understand current equipment and practices to refine estimates of available potential for these customers.
	19	Target outreach to the largest transportation customers to understand their likelihood of participating in future energy efficiency programs, including to what extent and on what timeline, when considering program design.
Social Cost of Greenhouse Gasses Calculations	20	Explicitly note costs of greenhouse gas emissions established in RCW80.28.395 when analyzing avoided costs.
	21	Clearly account for emissions occurring in the gathering, transmission, and distribution of natural gas, providing itemization, a total value of these emissions, and the ratio of these emissions to throughput for the purposes of avoided cost calculations.
	22	Incorporate distribution system emissions data into Distribution Scenario Decision-Making Process criteria if applicable.
	23	Include both the cost of compliance with the CCA and the SCGHG for conservation in the base case in the 2025 IRP.
	24	When calculating the natural gas energy efficiency target for 2024- 2025, use the avoided cost from the Social Cost of Carbon Case in Appendix 6.4.
Alternative Fuels	25	Consider hydrogen and landfill gas for the purposes of lowest reasonable cost analysis unless it can demonstrate a reason not to consider these fuels.
	26	Convert figures similar to 4.16 through figure 4.21 to time series graphs featuring box and whisker plots.
IRP Modeling	27	Highlight and offer appropriate cautions in its analysis wherever PLEXOS yields results or behaviors that would be unlikely to be anticipated or enacted by a human planner.
	28	Highlight and offer appropriate caution in its analysis wherever PLEXOS uses resources in its portfolio in a manner that does not accord with current best practices or current technological means.
	29	Rely upon human expertise to vet and verify all results generated by PLEXOS.
Decarbonization Plan and Electrification Analysis	30	Consult with the TAC and parties to the GRC to discuss what a decarbonization plan should entail, submit a specific workplan, and provide a decarbonization plan in the 2025 IRP.
	31	Refine the electrification analysis with input from interested persons.
	32	Refine assumptions around electrifying loads and run additional sensitivities that illuminate a range of possible costs of electrification depending on how loads electrify.

Secondary Actions and Attachments

OPUC Staff - Requests

Request 1: Future IRPs should include a clearer explanation of the PRS, and a more transparent presentation of the assumptions and processes used in creating the PRS, including examples noted by Staff.

Request 2: Staff requests Avista engage the TAC in discussion of the value of NPVRR analysis relative to levelized-cost analysis.

Request 3: Avista engage the TAC in considering the merits and drawbacks of modeling state specific resource and system investments.

Request 4: Staff requests that the latest information on possible distribution projects, including any proposed traditional investments or proposed NPA, be included in future IRP Updates.

Request 5: Staff requests that the possible impacts (at least on the Company's revenue requirement and scenario analysis) of line extension allowance elimination be taken up by the TAC with the goal of determining how to best reflect expected impacts in future IRPs.

Request 6: Staff requests that the Company report to the TAC in late 2024 on the low-income hybrid heating pilot including relevant program details, progress to-date, lessons learned, findings about the potential of such a program to meet CPP compliance and to mitigate upward rate pressure, and learnings on how to model such a program in future IRPs.

Request 7: Staff requests Avista vet demand response modeling parameters (such as costs, increments, potential, and ramp rates) with TAC members.

Request 8: Staff requests that Avista engage the TAC in a discussion of how the value of Interruptible loads can be folded into resource planning.

Request 9: Staff requests Avista engage a representative set of Interruptible customers to study interest in participating in demand response offerings, and under what conditions, with results to be shared with the TAC.

Request 10: In the IRP Update, Staff requests that Avista include a table of expected CPP compliance costs.

OPUC Staff – Attachment A

- **Ratepayer Incentive Value**

  The Ratepayer Incentive Value includes both the cost of the ratepayer to convert and the benefit the ratepayer's decision to electrify provides to gas system operations and downstream costs. Staff expects the feasibility of conversion to be constrained by the equipment lifecycle costs (equipment costs and operation costs over the lifetime of the appliance) and available electric grid capacity. Equipment cost calculations could foreseeably leverage precedent used within the Docket No. UM 1893, available policy incentives, and data collected from regional electric appliance sales and Energy Trust of Oregon heat pump programs. Staff is not convinced that electric rates are the best indicator of operation costs. Instead, Staff requests Avista work with Energy Trust and electric utilities to consider bill impacts or other metrics to measure operation costs by end-use. In any event, given the sensitivity of lifecycle costs to region, Staff stresses that Avista use regionally appropriate efficiencies, equipment and operation costs, and weather forecasts for Avista's service territory.141 Moreover, Staff believes that understanding the Ratepayer Incentive Value of electrification will require some form of scenario and data sharing between gas and electric utilities to identify where electrification is feasible based on available capacity on the electric grid to handle the new entry of electric appliances. To determine the benefits the ratepayer provides to the system through their decision to electrify, Staff requests the Company consider how the decision provides downstream benefits such as reduced emissions, reduced need for higher-cost alternative fuels, reduced transportation and distribution costs over the long term. The decision to electrify may also provide reliability benefits to the gas system during winter peak through released firm pipeline capacity. In determining a compensation cost for these savings and gas system operation benefits Staff sees benefit in considering existing electric sector incentives, including time-of-use rates, net metering, and capacity payments. Staff recognizes that the price to switch out appliances and electric rates rising above marginal cost are key considerations in a property owner's decision to electrify. If the benefit of the ratepayers' investment is greater than the costs, it can indicate new entry of the electric unit and a corresponding retirement of the gas unit.

- **Policy Incentives**

  Policy incentives include external, non-ratepayer funding sources. These can supplement an incentive strategy without impacting gas rates. For example, the IRA provides tax credits and rebates to reduce the purchase cost for electric panel upgrades and heat pumps, whose high costs can be a barrier to electrification. Notably, maximizing IRA incentives is crucial in the near term, as available IRA incentives decrease annually and are unavailable after 2032. As shown in the figure below, in the workpapers accompanying the IRP, Avista forecasts that the cost of electrification will increase year over year and spike in 2032 with the termination of IRA financing. This suggests that it will be incrementally more expensive for Avista to incentivize electrification over time. Figure 7 below shows Avista's forecasted cost for electric space heat inclusive of a 50 percent reduction in conversion costs for IRA incentives and increasing electric rates.

- **Company Cost Value**

  The Company Cost Value portion of the incentive strategy looks at the cost to the Company to proactively incentivize electrification. In other words, what portion of the Ratepayer Incentive Value is the Company willing to pay? Staff recognizes that electrification reduces consumption. This manifests as a cost to the LDC through reduced returns and lost capital investment opportunities. Unless the company can anticipate a return on the investment, their willingness to incentivize electrification is lower because of these reduced revenue requirements. Using avoided cost calculations may help to understand Avista's willingness to pay. Staff anticipates working with the Company to deepen conversation around electrification and avoided cost within the Docket No. UM 1893.

- **Conclusion**

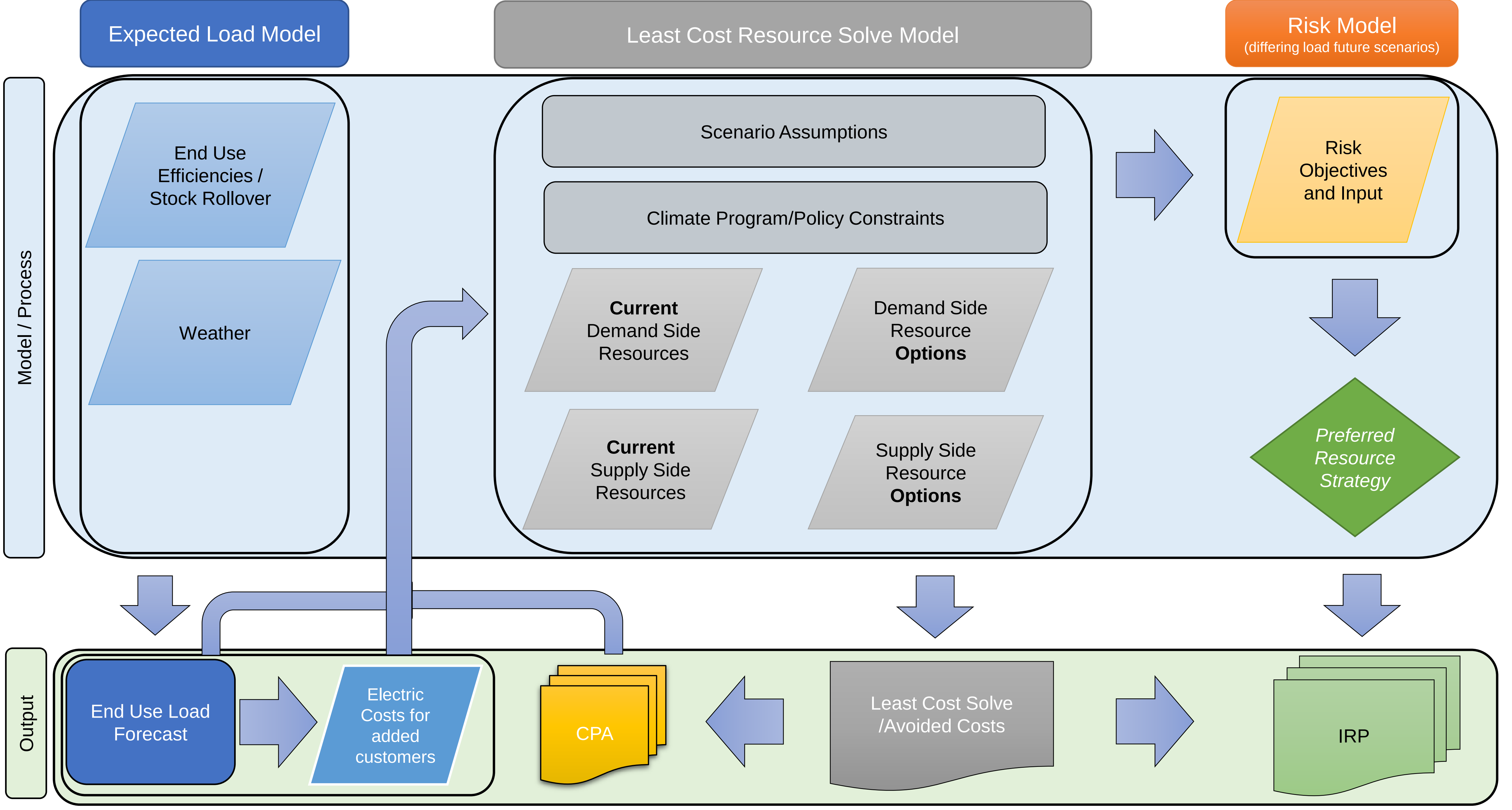
  As discussed in more detail in Section 6.4, Staff is interested in hearing from stakeholders when identifying the right incentive level. Staff recognizes that this will likely require the sharing of data and scenarios between gas and electric utilities and recommends possible pathways in Section 6.3. Moreover, an electrification incentive strategy should be considered alongside other energy efficiency and weatherization programs.

OPUC Staff – Attachment C

The Company should update its DSP practices and IRP processes to include:

1. Future distribution system planning should identify the rationale for projects as either Safety/General System Reliability, or Customer Growth/Reliability Related to Growth. a. When proposing growth-driven projects in IRPs the utility should be prepared to present project data on: relationship to CPP compliance strategy, modeling and verified measurement, local load forecast, and assessment of alternatives through the NPA framework.
2. Future distribution system planning should include an NPA framework in Oregon. The framework should include:
    a. NPA analysis will be performed for supply-side resources (these include but are not limited to all resources upstream of Avista's distribution system and city gates, and supply-side contracts) and for distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects (a group of projects that are interdependent or interrelated).
    b. b. NPA analysis will include cost benefit analysis that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices. Non-Energy Impacts must be included as part of the NPA analysis.
    c. NPA analysis will include electrification, targeted energy efficiency, targeted demand response, and other alternative solutions.
    d. NPA analysis should look forward five years to allow ample time for evaluation and implementation.
    e. NPA analysis will include an explanation of solutions considered and evaluated including a description of the projected timeline and annual implementation rate for the solutions evaluated, the technical feasibility of the solutions, and the strategy to implement the solutions evaluated.
    f. NPA analysis should include an explanation of the resulting investment selection (either NPA or a traditional investment) including the costs and ranking of the solutions, and the criteria used to rank or eliminate them. i. If a NPA is not selected and the reason is insufficient implementation time, it should include steps the Company will take to perform NPA analysis to provide sufficient implementation time for future projects.
3. Future IRPs should include the results of distribution system planning, including project data and NPA analysis for any proposed traditional investments, and NPA analysis for any proposed NPA.
4. Future IRPs should include a database containing information about feeders, in service dates of pipes, and lowest recent observed pressures.

Modeling and Assumptions Overview


Expected Load Model
Least Cost Resource Solve Model
Risk Model
(differing load future scenarios)
Model / Process
End Use Efficiencies / Stock Rollover
Weather
Scenario Assumptions
Climate Program/Policy Constraints
Current Demand Side Resources
Demand Side Resource Options
Current Supply Side Resources
Supply Side Resource Options
Risk Objectives and Input
Preferred Resource Strategy
Output
End Use Load Forecast
Electric Costs for added customers
CPA
Least Cost Solve /Avoided Costs
IRP

Load Assumptions

- PRS load input will rely on current known state policy, codes and requirements
  - WA SBCC will be included in load forecast baseline
  - Line extension program expirations will be included in forecast baseline
    - 2027 end date in Oregon
    - 2024 end date in Washington
- Hybrid heating begins below 40 degrees Fahrenheit
  - Chosen as an average between furnace manufacturer coefficient of performance values (COP)
  - Value is also used by fundamental forecast houses in their electrification evaluations
- The end use model can select higher efficiencies if cost effective or standard at rollover
  - Model will select cost effective pathway (gas or electric) and distribute load
- Scenarios will estimate risk of differing load expectations

Cost Assumptions

All quantifiable current and estimated costs:

- Interstate pipeline transportation
- Storage
- Expected cost of natural gas by supply basin (AECO, Malin, Rockies, Stanfield, Station 2, Sumas)
- Alternative fuels (RNG, Methanation, Hydrogen – all forms, carbon capture)
- Compliance mechanisms to climate programs (Allowances, Offsets, CCIs)
- Social cost of carbon @ 2.5%, where applicable
- Economic non energy impact (NEI) adders
- Energy Efficiency per the CPA
- Demand Response potential costs per the CPA
- New capital distribution projects by area
- Maintaining the LDC
- Electricity cost by area (including distribution, transmission additions)
- Electrification (including efficiencies, costs by area, including distribution and transmission additions)

Output

- An average rate, with power costs, will be provided by scenario
- Emissions by scenario
- A levelized cost by scenario
- A net present value revenue requirement (NPVRR)
- Risks
- Energy Burden

Scenarios

Scenarios – Deterministic & Monte Carlo	Description
PRS	*Our expected case based on assumptions and costs with a least risk and least cost resource selection. This scenario includes all known policies and orders from Idaho, Oregon and Washington. Assumes 4.5 RCP weather.*
High Growth on Gas System	A high case to measure risk of additional customer and meeting our emissions and energy obligations
High Electrification	The highest expected conversions to the electric system. Electric IRP indicates 80% loss by 2045
PRS - Includes CPP	PRS assumptions, but includes the CPP expectations going forward from 2025
No Climate Programs	PRS assumptions with no climate programs
Low Natural Gas Use Case	This scenario will include high electrification, with the 8.5 RCP for weather, high cost of alternative fuels and a high cost of allowances in WA.

*Each scenario will have a rate per class, a cost with power included, emission and energy burden

Scenarios – Deterministic Only

Scenarios – Deterministic Only	Description
Low Alternative Fuel Costs	A scenario to measure resource selection with a lower-than-expected set of Alternative Fuel costs by source
High Alternative Fuel Costs	A scenario to measure resource selection with a higher-than-expected set of Alternative Fuel costs by source
High Natural Gas Prices	Higher than expected prices for natural gas
Average Case Weather	Non climate change projected 20-year history of average daily weather and excludes peak day
High CCA Costs	Considers a high cost for allowances in Washington

*Each scenario will have a rate per class, a cost with power included, emission and energy burden

Scenarios – Deterministic Only

Scenarios – Deterministic Only	Description
RCP 8.5 Weather	Weather will use the RCP 8.5 future
RCP 6.0 Weather	Weather will use the RCP 6.0 future as the average between RCP 8.5 and 4.5
Resiliency	Supply will be selected to create a resilient system
No New Natural Gas	Restrict customers after line extensions expire in Oregon and Washington to 0 growth
Hybrid Heating	A scenario to include hybrid heating for temperatures below 40 degrees Fahrenheit
Diversified Portfolio	This scenario will include electrification, 25% of supply from RNG, 25% of supply from methanation and 7% from hydrogen all after 2035.
Social Cost of Carbon	A scenario to value resources in all locations using the Social Cost of Carbon @ 2.5% and includes upstream emissions

*Each scenario will have a rate per class, a cost with power included, emission and energy burden

Modeling Risk

- 18 total scenarios
  - Deterministically solve a set of resources to meet variability in the scenarios for a stochastic set of futures
- Run 500 monte carlo futures for the 4 distinct load scenarios to determine risk
- Efficient Frontier may be used to select least cost and least risk solution

Avista CROME High Level Overview

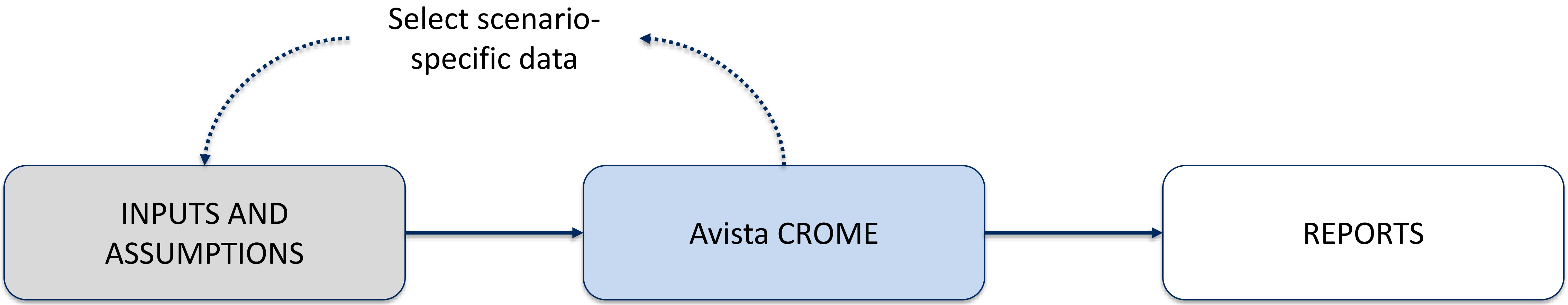
Comprehensive Resource Optimization Model in Excel

Michael Brutocao
Natural Gas Analyst

Timeline: IRP Modeling Software

Prior to 2023		2023 IRP		2025 IRP
SENDOUT®	→	PLEXOS®	→	Avista CROME

High Level Overview

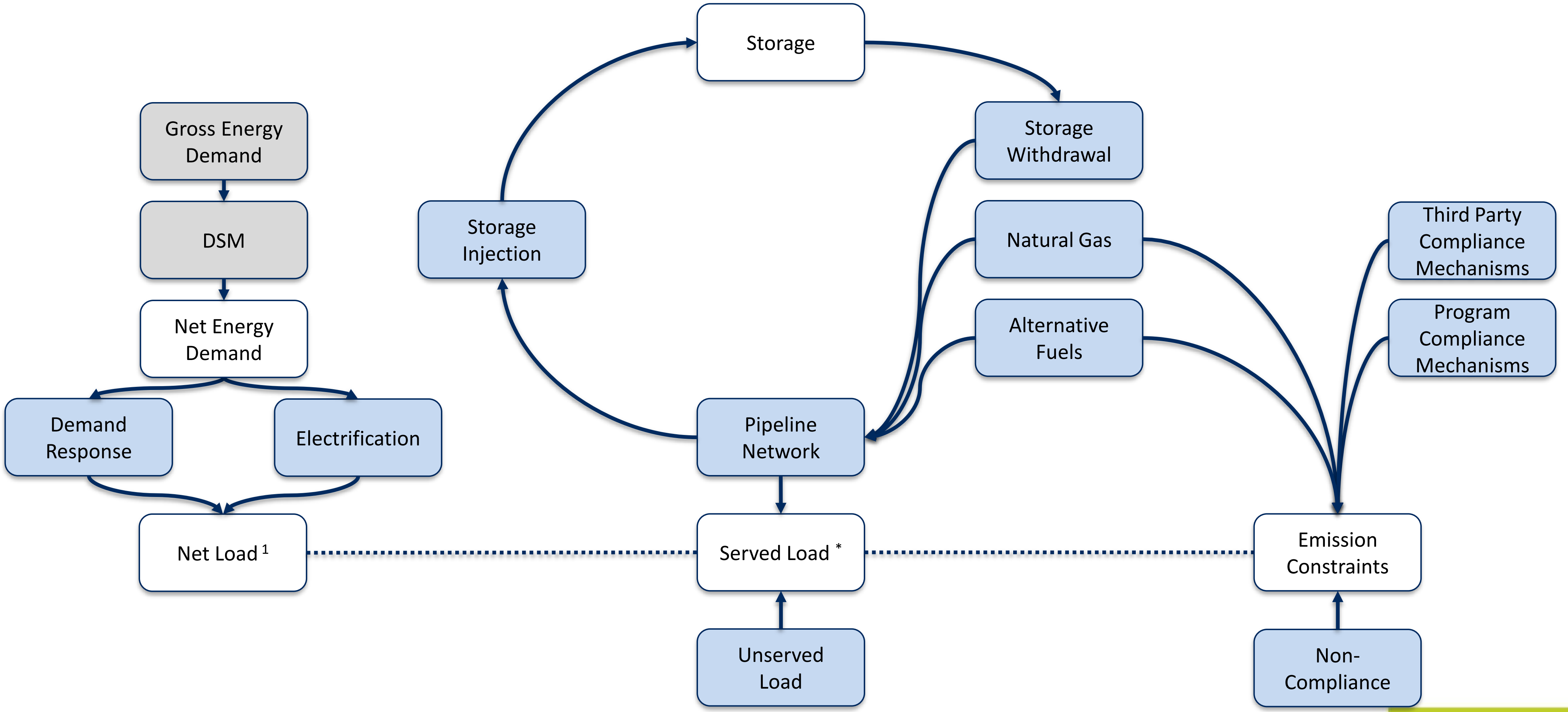


- Inputs and assumptions are stored here.
- Data is prepared for CROME.

- Inputs, assumptions, and constraints are brought together.
- Decision points are optimized to produce least-cost solution.

- CROME solution data updates templates for summary statistics and graphics.

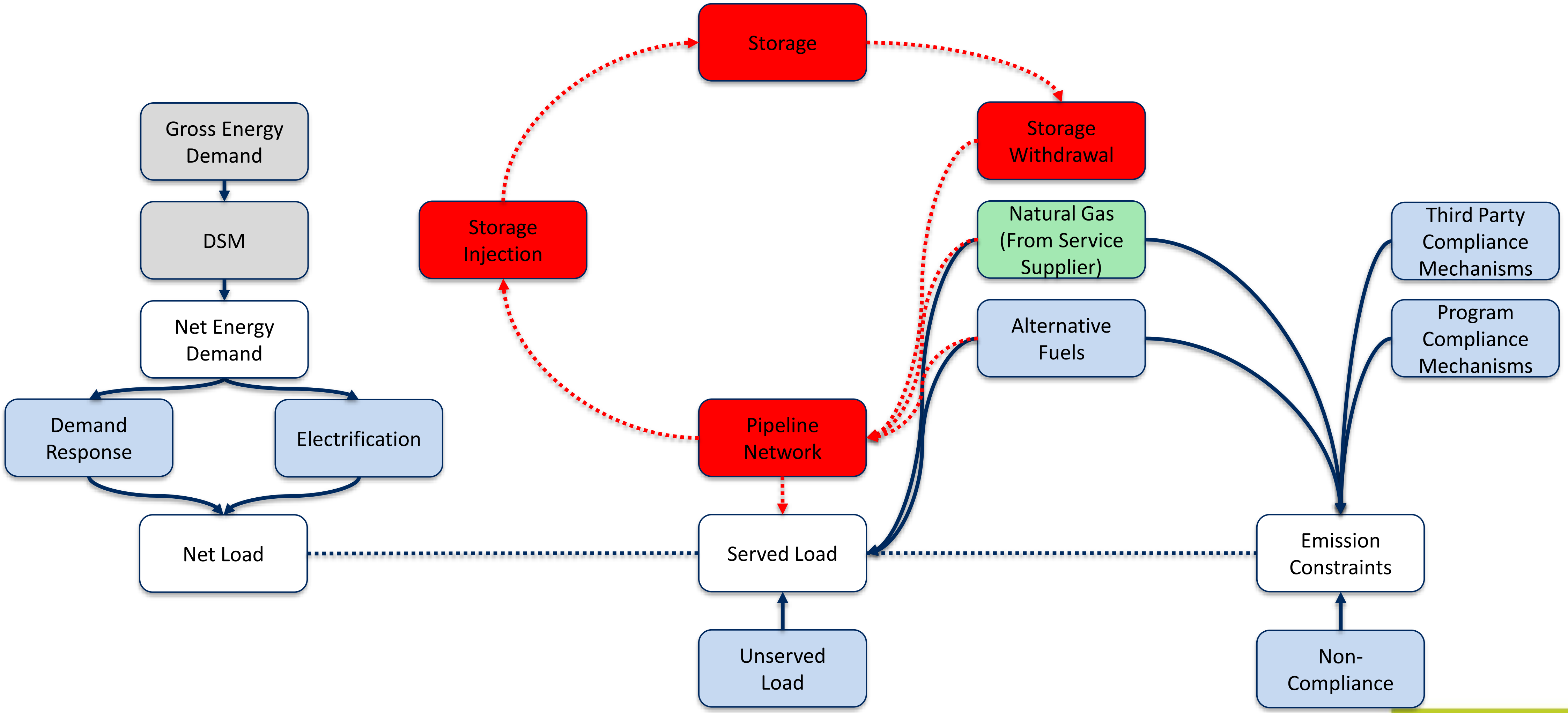
Solving for Residential, Commercial, and Industrial Loads



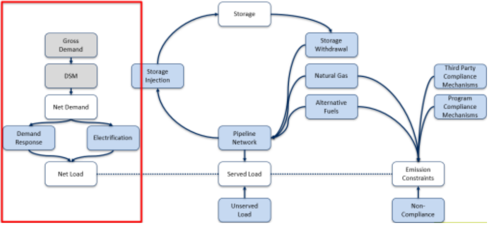
* NEI cost consideration

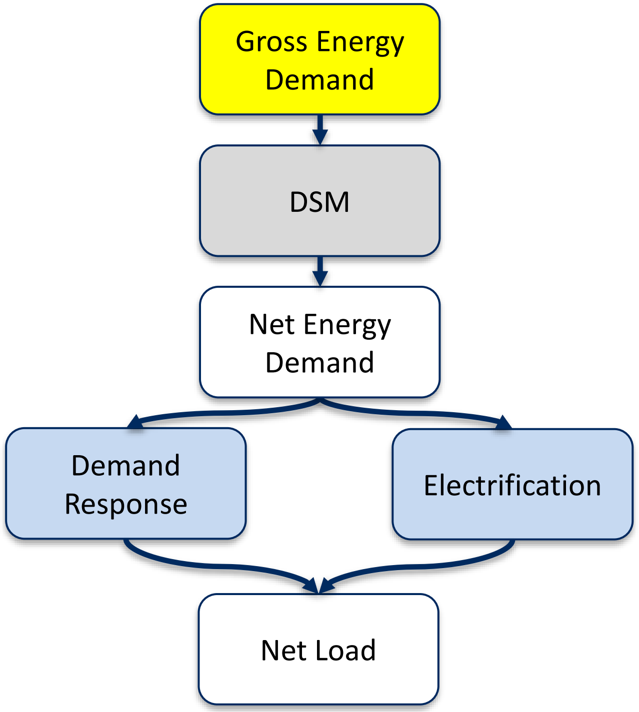
[1] Cost of expected distribution projects

Solving for Transport Customer Loads



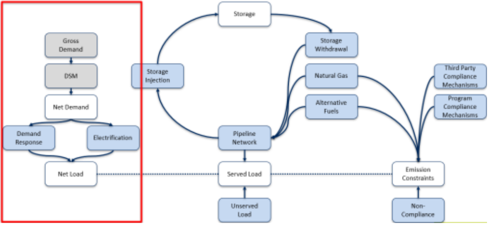
NET LOAD

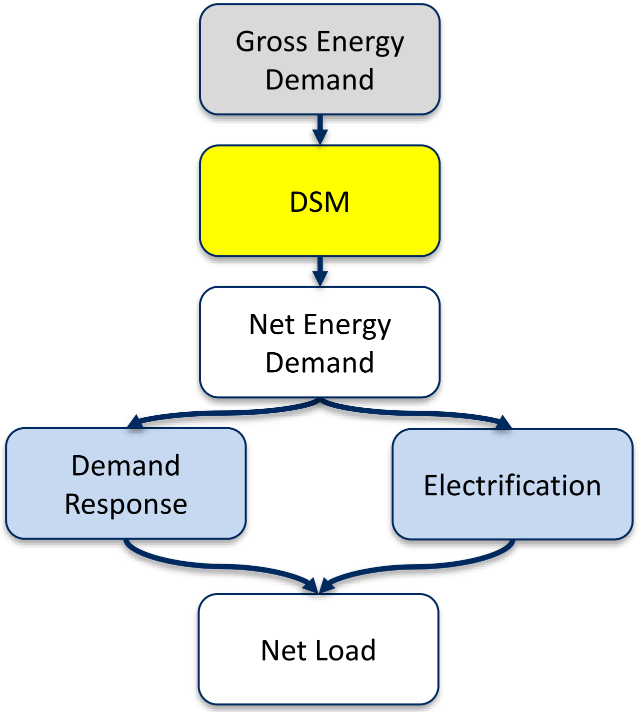




Gross Demand

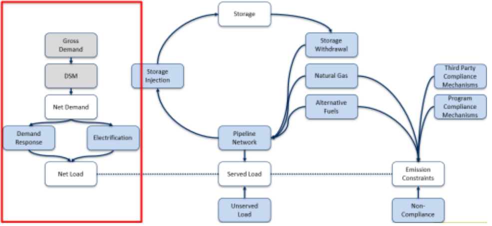
Considerations:	Number of customers by end-use Base use per customer Heating use per customer Weather
Optimization Decision:	N/A
Points:	All modeled areas and customer classes
Frequency:	Daily

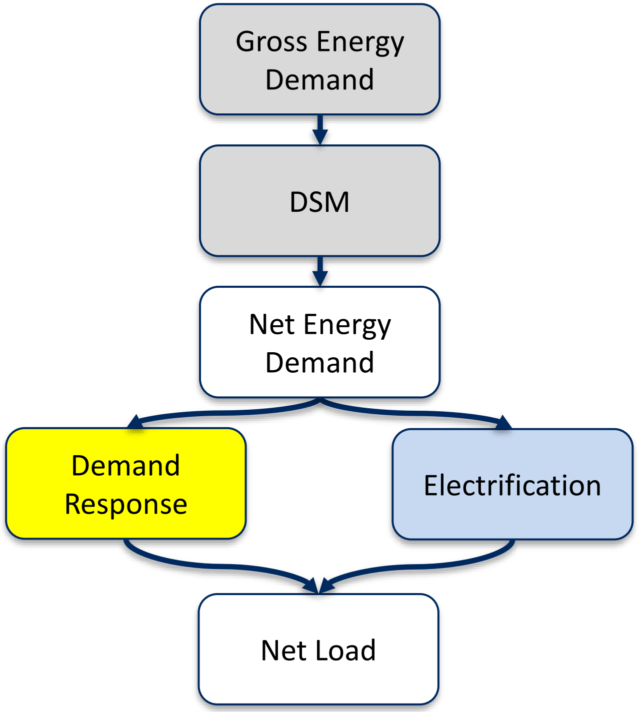




Demand Side Management

Considerations:	Avoided cost by area and customer class Number of customers by end-use CPA from AEG/ETO
Inputs:	UCT (ID), TRC (WA, OR)
Points:	All modeled areas and customer classes
Frequency:	Daily





Demand Response

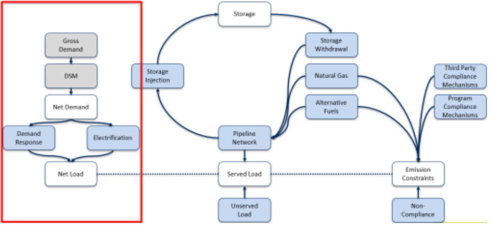
Considerations: Cost

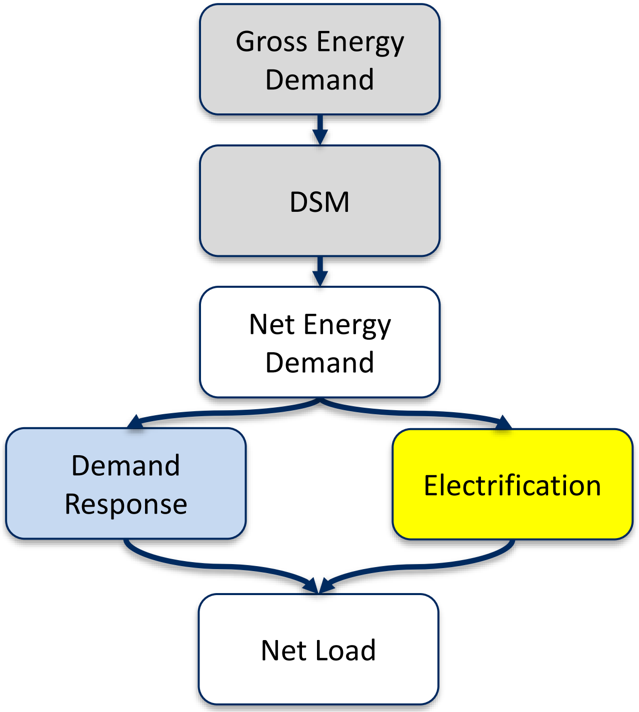
Available “supply” by program, area and customer class

Optimization Decision: Quantity “purchased”

Decision Points: All modeled areas and customer classes

Decision Frequency: Daily



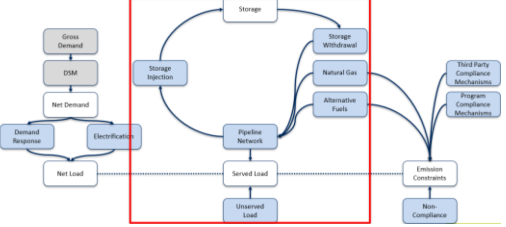


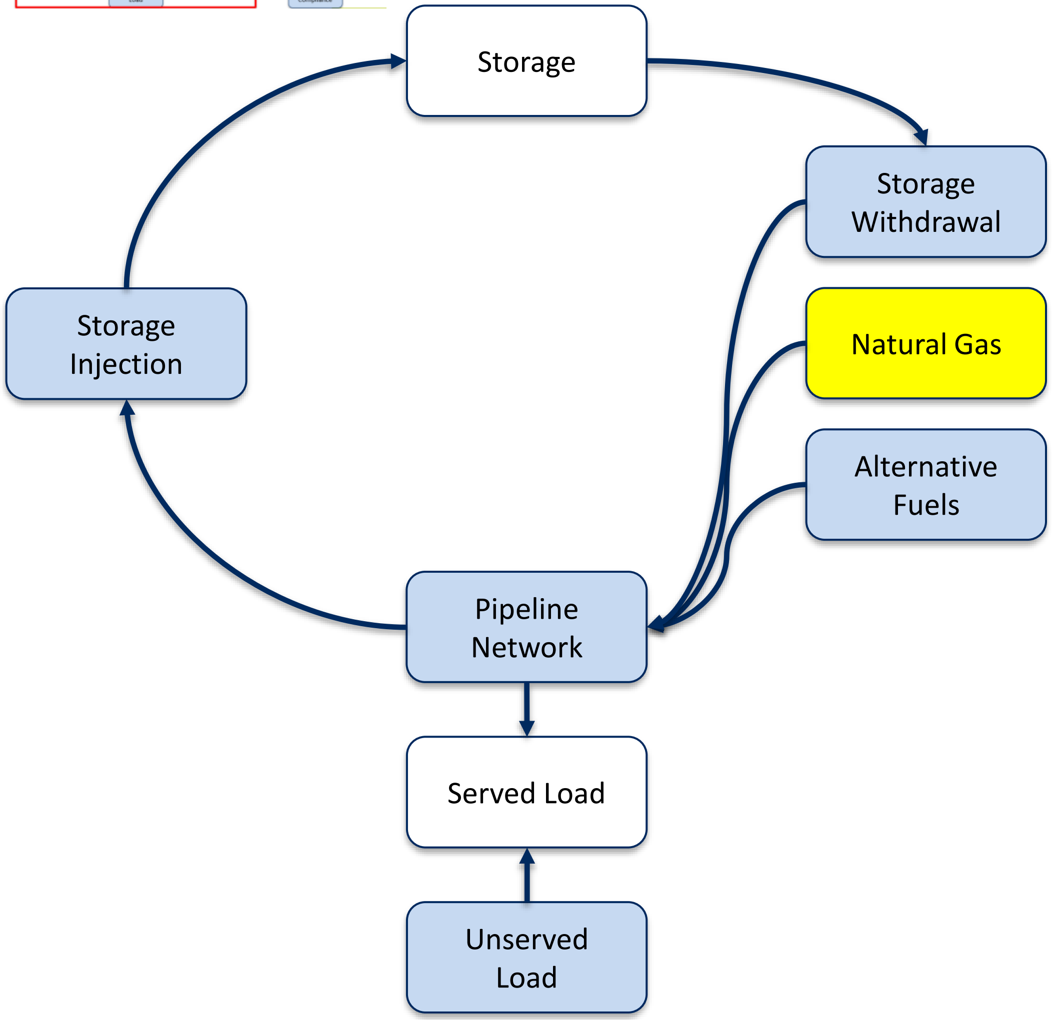
Electrification

Considerations:	Cost Available "supply"*
Optimization Decision:	Quantity "purchased"
Decision Points:	Residential and commercial classes (OR, WA)
Decision Frequency:	Annual

* This is constraining the optimization decision

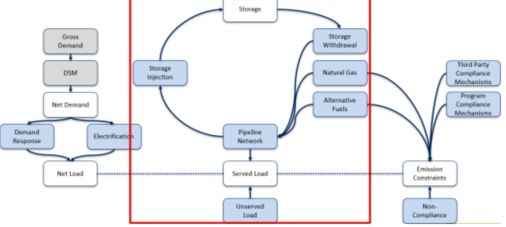
SERVED LOAD

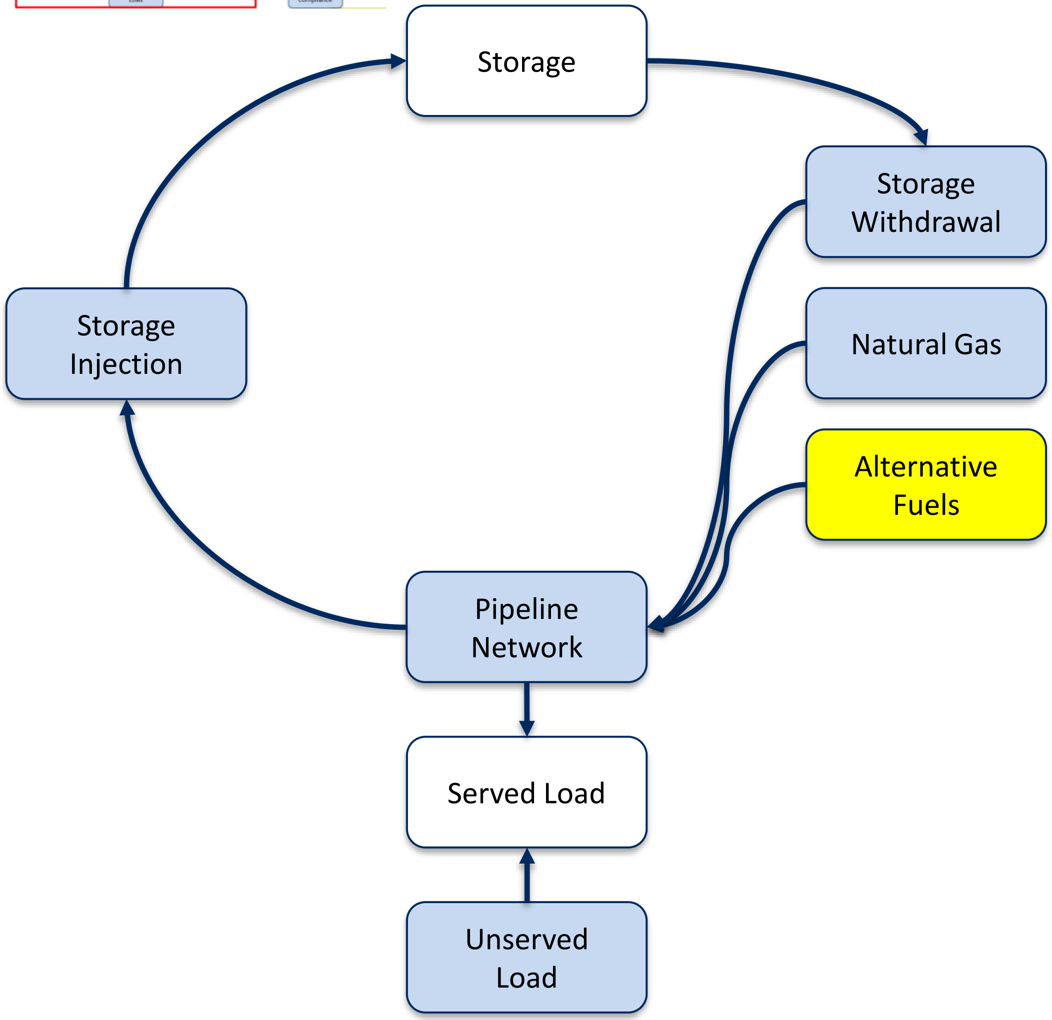




Natural Gas

Considerations:	Cost	
Optimization Decision:	Quantity purchased	
Decision Points:	AECO	Stanfield
	Malin	Station 2
	Rockies	Sumas
Decision Frequency:	Daily	





Alternative Fuels

Considerations: Cost

Available supply *

Max blend percent *1

Optimization Decision: Quantity purchased

Decision Points: Hydrogen (7 forms)

RNG (5 forms)

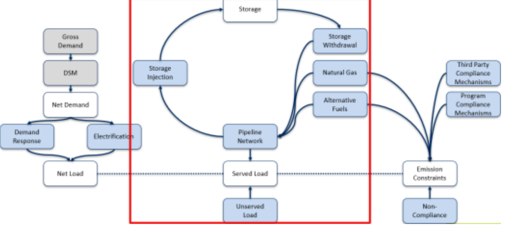
Synthetic methane (3 forms)♣

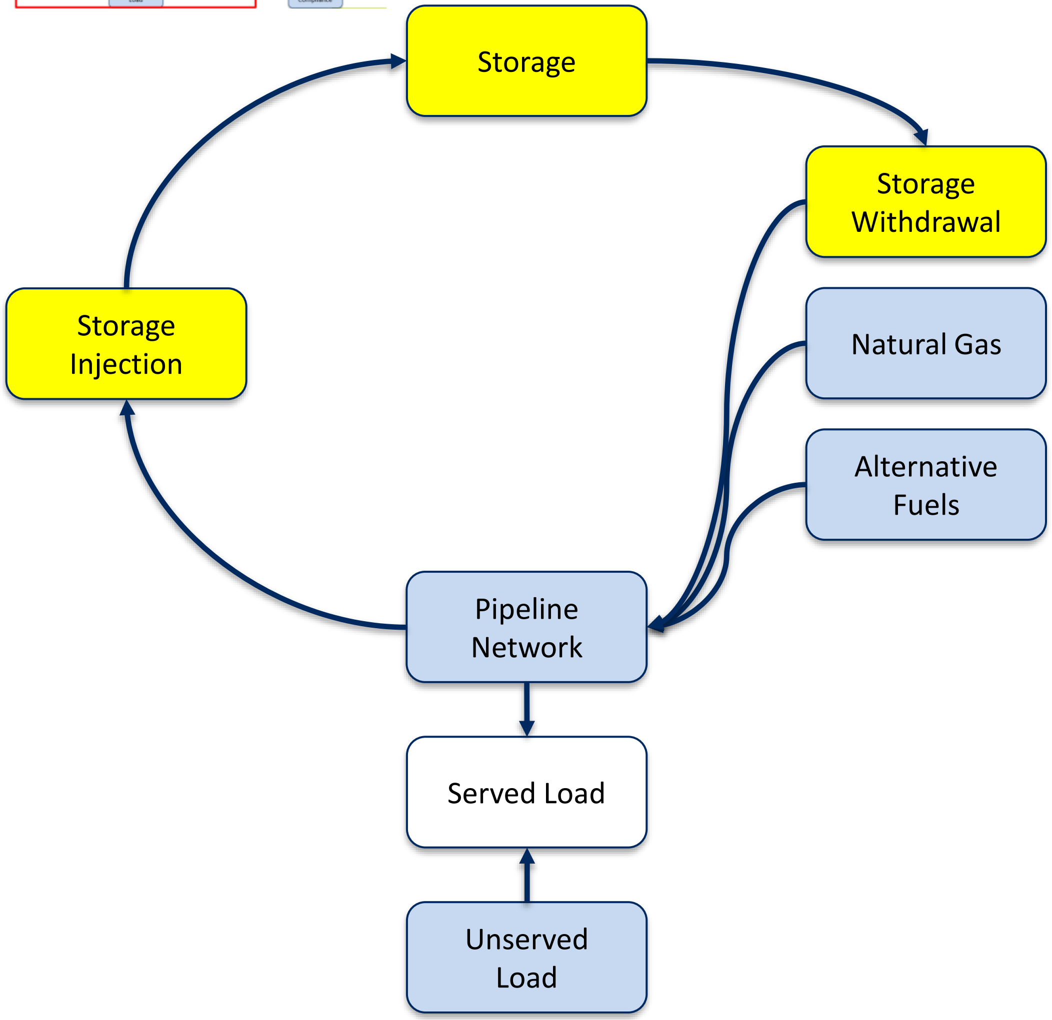
Decision Frequency: Annual

* This is constraining the optimization decision

1 A daily constraint on the volume of hydrogen blended into pipeline

♣ Model decision frequency to be determined by alternative fuel study results





Storage

Considerations: Min/max volume *

Max daily injection/withdrawal *

Capital & overhead

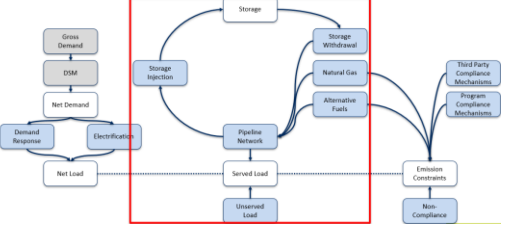
Carrying rate

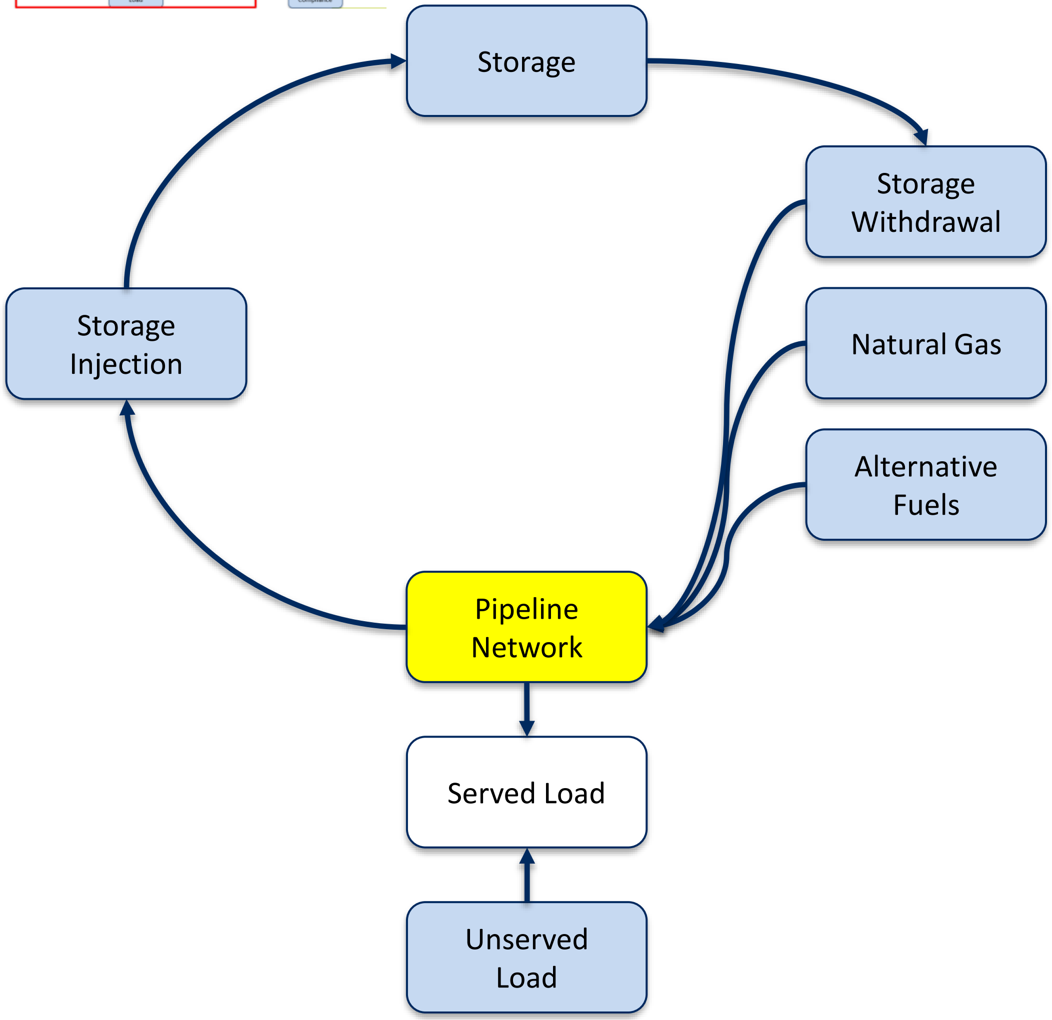
Optimization Decision: Quantity injected/withdrawn

Decision Points: Jackson Prairie

Decision Frequency: Daily

* This is constraining the optimization decision





Pipeline Network

Considerations: Flow capacity *

Reservation rate

Variable rate (flow charge)

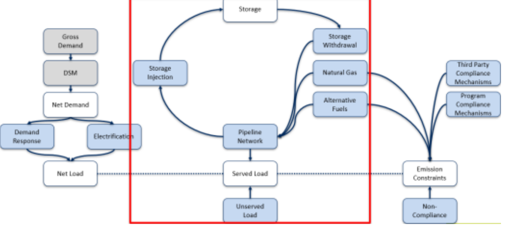
Fuel loss

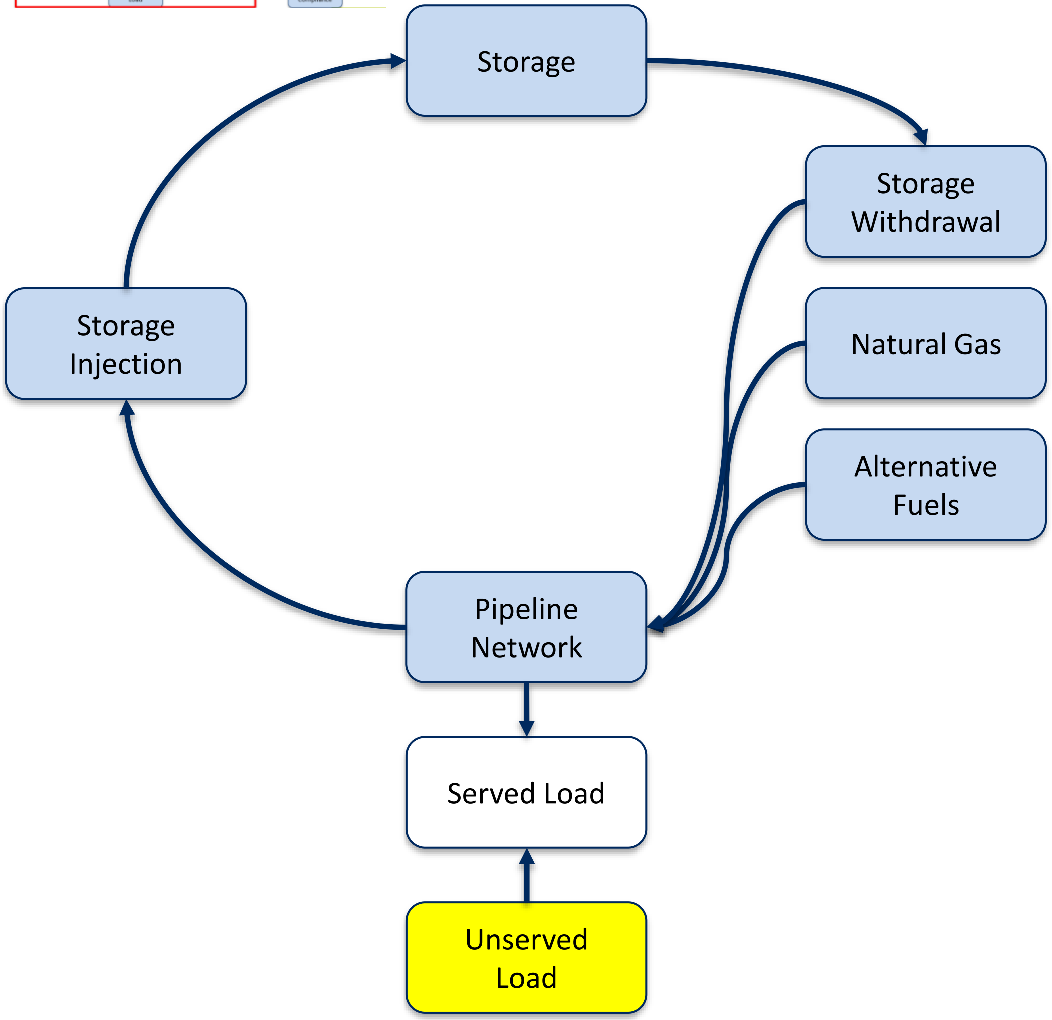
Optimization Decision: Segment flow

Decision Points: All pipeline segments in network

Decision Frequency: Daily

* This is constraining the optimization decision





Unserved Load

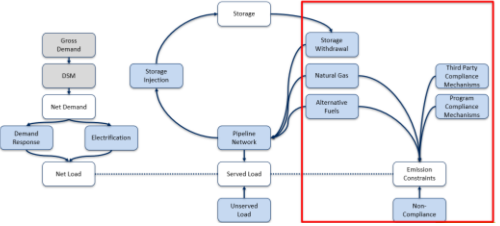
Considerations: Cost

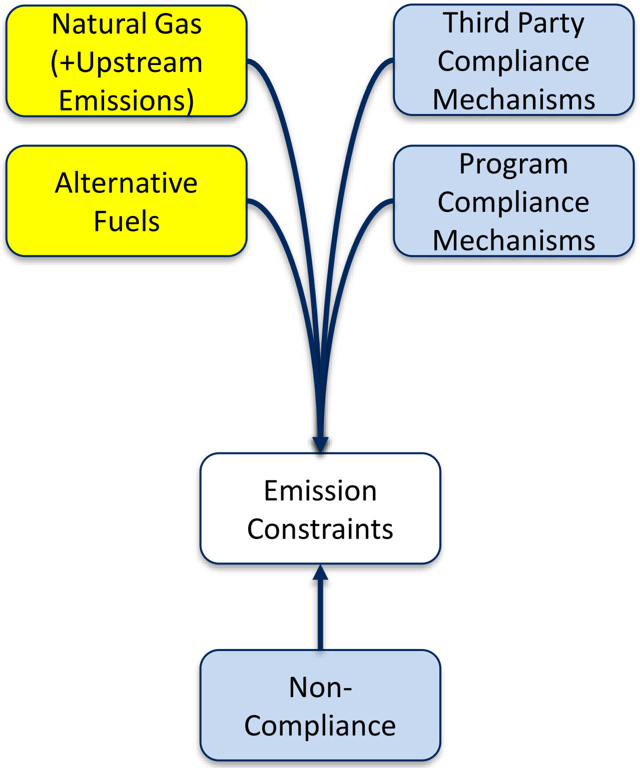
Optimization Decision: Quantity unserved

Decision Points: All modeled areas and customer classes

Decision Frequency: Daily

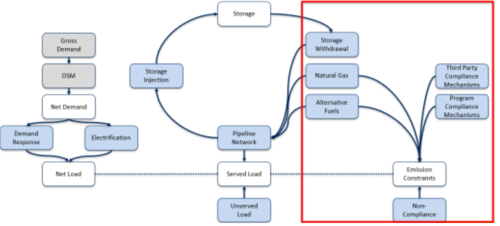
EMISSIONS

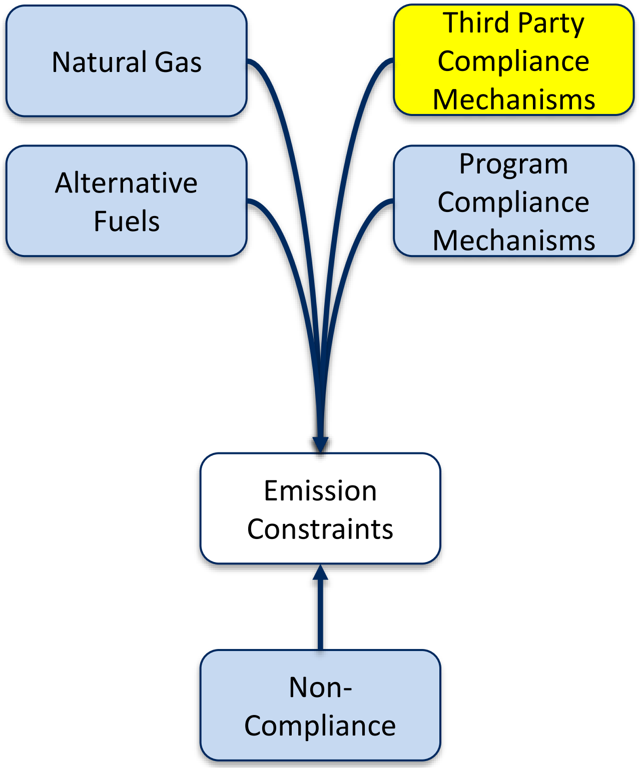




Natural Gas & Alternative Fuels

Considerations:	Carbon emissions
Optimization Decision:	Quantity purchased
Decision Points:	Same as in served
Decision Frequency:	Annual, daily

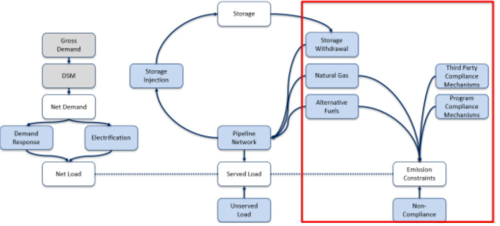


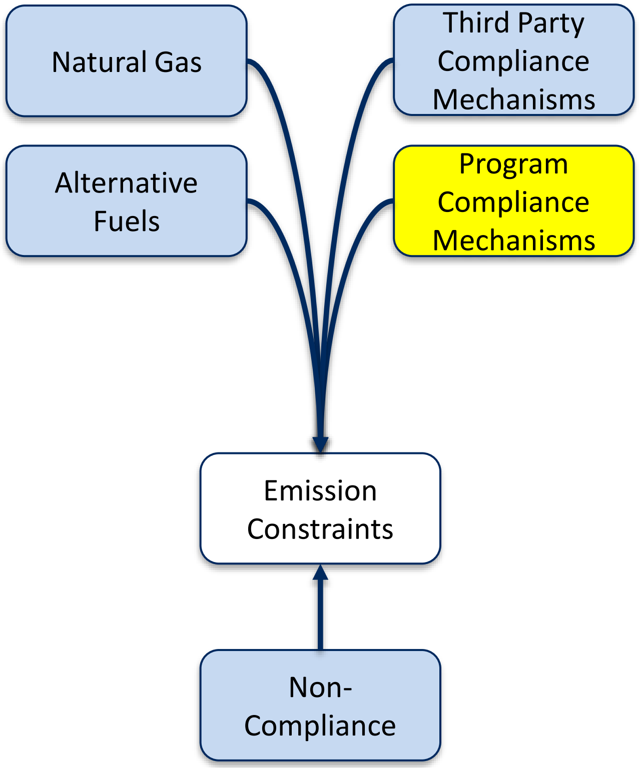


Third Party Compliance Mechanisms

Considerations:	Cost
	Available supply *
Optimization Decision:	Quantity purchased
Decision Points:	Renewable thermal credits (3 forms)
	Carbon capture (4 forms)
Decision Frequency:	Annual

* This is constraining the optimization decision

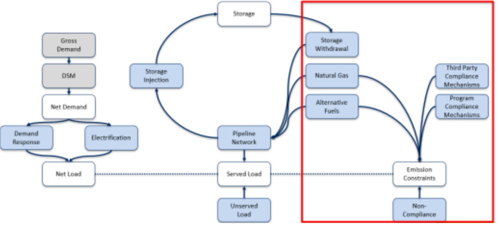


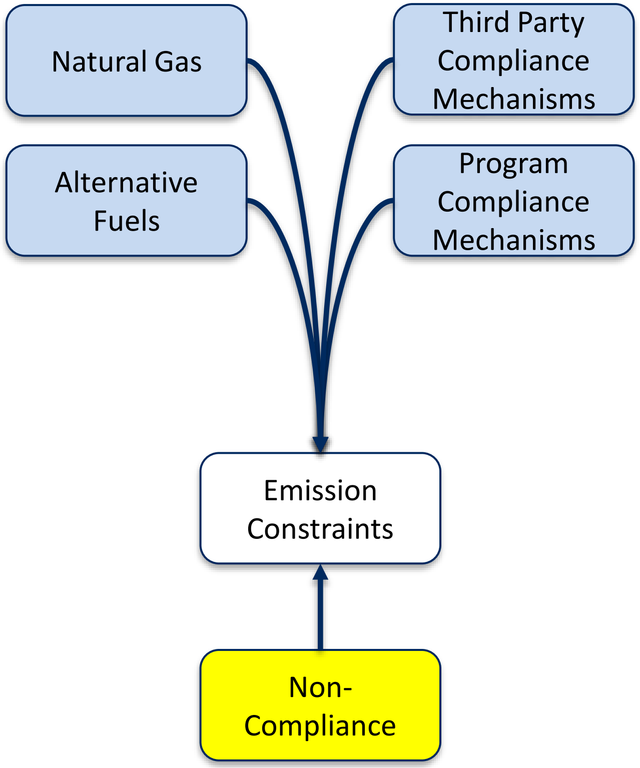


Program Compliance Mechanisms

Considerations:	Cost
	Available supply *
Optimization Decision:	Quantity purchased
Decision Points:	Allowances (CCA)
	Offsets (CCA)
	CCIs (prior CPP)
Decision Frequency:	Annual

* This is constraining the optimization decision





Non-Compliance

Considerations:	Cost
Optimization Decision:	Quantity
Decision Points:	Climate Commitment Act Prior Climate Protection Program
Decision Frequency:	Compliance period, annual (CCA)