2021-2022 IRP Technical Conference
February 9, 2021

Dominion Energy®

2021 IRP Schedule

February 9, 2021 – Technical Conference

- Review of IRP Standards and Guidelines
- Review of 2020 PSC Order Regarding IRP
- March 2020 Stakeholder Meeting Review
- Rural Expansion Update
- LNG Update
- Hedging

May 18, 2021 – Technical Conference

- IRP Project Detail Discussion
- Long Term Planning Update
- Hydrogen Pilot Update
- Future STEP Project Update

April 28, 2021 – Technical Conference

CONFIDENTIAL MEETING

- Heating Season Review
- System Integrity Update
- Wexpro Matters (Confidential)
- RFP Review (Confidential)

June 22, 2021 – Technical Conference

- Presentation and Review of 2021-2022 IRP

IRP Standards and Guidelines (2009)

Guideline	Update
Review latest quarterly variance report	April 28, 2021 Tech Conference
Changes to customer growth models	IRP Report – Customer & Gas Demand Forecast Section
Changes to linear programming optimization (LPO) model (SENDOUT)	IRP Report – Final Model Results Section
Changes to DSM models	IRP Report – Energy Efficiency Section
Supply/demand forecasts, SENDOUT and DSM results	IRP Report – Customer & Gas Demand Section
Gas quality and gas storage issues	IRP Report – Gathering, Transportation, & Storage Section
Changes to Gas Network Analysis (GNA) models	IRP Report – System Capabilities and Constraints
GNA model results	IRP Report – System Capabilities and Constraints
Integrity management issues	April 28, 2021 Tech Conference
Other issues	Scheduled as needed
Post- IRP Filing	June 22, 2021 Tech Conference

Review of 2020 PSC Order Regarding IRP

- 2020 IRP "generally complies with the requirements of the Standards and Guidelines"

- Adopted DEU's commitments to:
  - Include a "Supply Reliability" section to provide updates on the LNG facility and any other concerns
  - Provide pandemic-related updates in quarterly variance reports
  - Provide additional detail when management overrides the SENDOUT model in variance reports
  - Include summaries of stakeholder meetings in future IRPs and IRP-related technical conferences

Review of March 2020 Stakeholder Meeting

- IRP Technical Conferences
  - The Company will include all relevant issues and large projects discussed in the IRP in technical conferences
- Long-term Planning
  - The Company agreed to include a high-level discussion about large projects under consideration for construction beyond the 3-year timeframe
- Distribution Action Plan
  - Stakeholders clarified detail to be included
- High Sendout Day vs Design Day (Peak Day)
  - The Company agreed to provide a comparison in each IRP
- Joint Operating Agreement (JOA)
  - Stakeholders discussed the importance of the JOA and the Company agreed to include a more detailed discussion in each IRP

Review of March 2020 Stakeholder Meeting

- Integrity Management Variances
  - The Company agreed to provide a more detailed explanation of variances in the IRP
- Wexpro Well Shut Ins
  - The Company agreed to provide a more detailed explanation of how these are managed and variances in the IRP
- Lost and Unaccounted for Gas (LAUF)
  - The Company agreed to include analysis and additional detail regarding LAUF gas in the IRP
- Hedging
  - Stakeholders discussed the current hedging program and the Company agreed to provide addition detail going forward
- Glossary
  - The Company agreed to add a Glossary to the IRP
- Emergency Planning
  - Stakeholders discussed emergency planning and determined that it should not be included in the IRP

2021-2022 IRP Outline

- Executive Summary
- Introduction
- Customer and Gas Demand Forecast
- System Capabilities and Constraints
- Distribution System Action Plan
- Integrity Management
- Environmental Review
- Purchased Gas
- Cost-of-Service Gas
- Gathering, Transportation, and Storage
- Supply Reliability
- Sustainability
- Energy Efficiency
- Model Results
- Guidelines
- Appendix
- Glossary

Rural Expansion

Eureka Update

- 2020 – Engineering work
  - Property acquisition
  - Permits
  - Design
- Jan 2021 – Insert in Eureka water bills
  - Invitation to call and sign up for service
  - Timeline
  - Q&A
  - As of Feb 8, 42 people have signed up for service
- Construction starts Early 2021
- On track to be in service late 2021

Happy New Year, Neighbor!

We are excited to share the news that 2021 will be the year Dominion Energy brings natural gas infrastructure to Eureka City. You may remember the open house we hosted in October 2019, when we gave you the opportunity to learn more and express your interest in receiving natural gas. During February and March, our team would like to meet to discuss next steps and acquire more information.

PLEASE VISIT OUR WEBSITE TO SET UP AN APPOINTMENT TIME BY CLICKING THE "SIGN UP NOW" BUTTON.

We are taking extensive precautions to protect everyone's safety and health by following recommendations regarding social distancing, handwashing, mask wearing and other virus-prevention measures. We hope to meet with you soon!

WEBSITE: DominionEnergy.com/UtahRuralExpansion
EMAIL: UtahRuralExpansion@DominionEnergy.com
TOLL-FREE NUMBER: 1-833-604-1893

PROPOSED TIMELINE

Outreach	Ongoing
Customer Appointments	February/March 2021
Construction Begins	Early 2021
In-Service	Late 2021

WHAT YOU NEED TO KNOW

Q: How much will new gas service from Dominion Energy cost me out of pocket?

A: Legislation was passed in 2019 that allows the infrastructure costs to be paid by all Dominion Energy Utah customers for approved projects.

Q: Will I need to buy new appliances?

A: In many cases, appliances can be converted from propane to natural gas. The cost of converting an appliance is the responsibility of the customer. Conversion and proper adjustment of appliances should be performed by a qualified contractor. If a propane appliance cannot be converted, a new appliance will be required.

Calculation of Spending Caps

- DNG from most recent general rate case $391,436,970
- 2% of DNG = $7,828,739
- 5% of DNG = $19,571,848
- Used tracker model to add investment

	2% cap Mains Revenue Requirement	5% cap Mains Revenue Requirement
Total Net Investment	$69,523,201	$173,808,007
Less: Amount currently in rates	$0	$0
Replacement Infrastructure in Tracker	$69,523,201	$173,808,007
Less: Accumulated Depreciation	($894,532)	($2,236,330)
Accumulated Deferred Income Tax	(4,401,528)	(11,003,821)
Net Rate Base	$64,227,141	$160,567,856
Current Commission-Allowed Pre-Tax Rate of Return	8.90%	8.90%
Allowed Pre-Tax Return (Line 6 x Line 7)	$5,716,216	$14,290,539
Plus: Net Depreciation Expense	$1,341,798	$3,354,495
Net Taxes Other Than Income (1.2% x Line 6)	$770,726	$1,926,814
Total Revenue Requirement	$7,828,739	$19,571,848
Adjustment for Interruptible Penalty	$0	$0
Remaining Revenue Requirement	$7,828,739	$19,571,848
Previous Revenue Requirement	$0	$0
Incremental Revenue Requirement	$7,828,739	$19,571,848

Rural Utah Expansion Allowed Spend Example

Year 1	Year 2	Year 3	Year 4	Year 5
$30	$10	$29.5	$30	$10

69.5 M spent years 1-3

69.5 M spent years 2-4

69.5 M spent years 3-5

Total spent years 1-5 = $109.5 million
Total allowed at current revenue requirement: $173.8 million
Remaining that may be spent in future years $64.3 million

Status on Future Expansions

- Goshen
  - Virtual open houses and surveys February 2021
  - File application mid-March 2021
  - If approved, construction begins ~Q1 – Q2 2022

- Green River
  - Working through legal complexities
  - Anticipating filing in May 2021
  - If approved, construction begins ~Q3 – Q4 2022

- These three projects should bring us close to budget of 2% cap
  - Still monitoring other expansion areas as budget allows

LNG Update

Magna LNG

Construction Progress Photos

Dominion Energy

[1]Footnote 1 is the #1, put into superscript (ctrl + shift + “+”).

[2]All footnotes should be Calibri size 7 with text same color as section title (second box down from black).

Magna LNG

Construction Progress Photos

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Magna LNG

Construction Progress Time-Lapse Video

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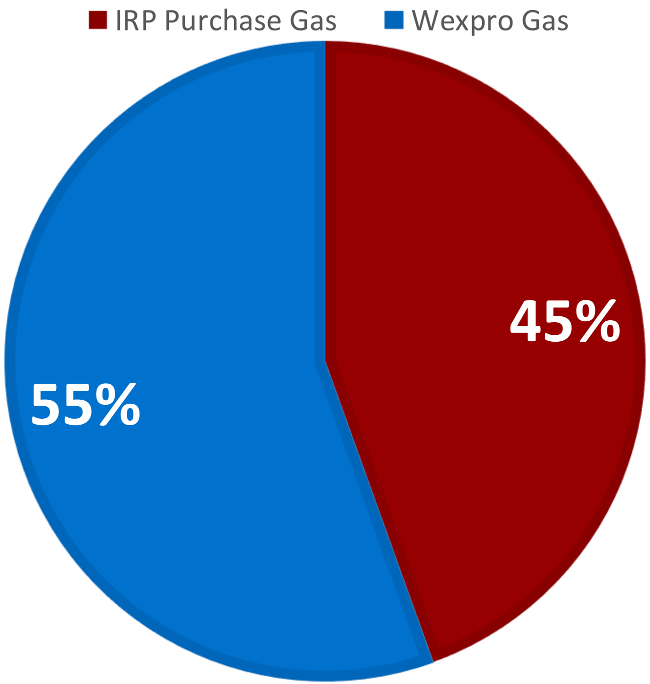
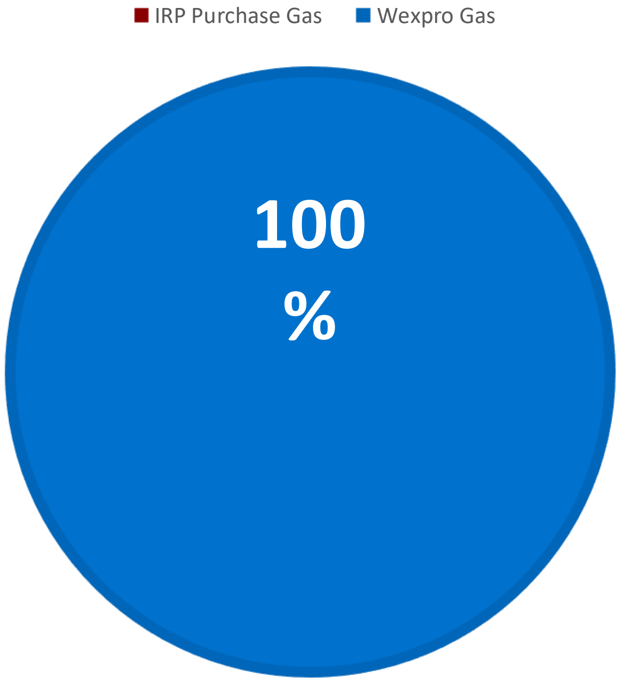
Hedging Update

Supply Breakdown Wexpro vs. Purchase
DEUWI

Annual - 2020 IRP Model

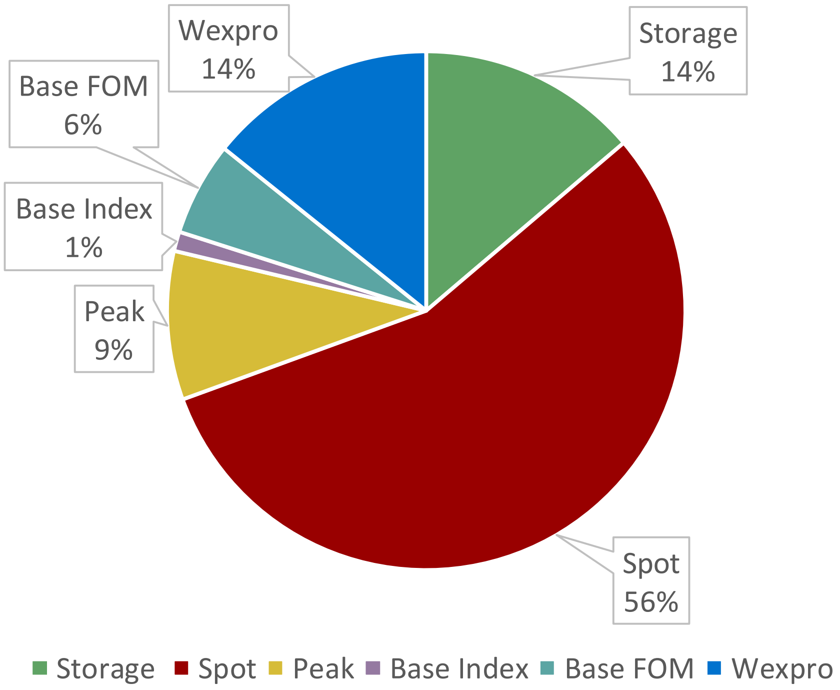


Summer Supply

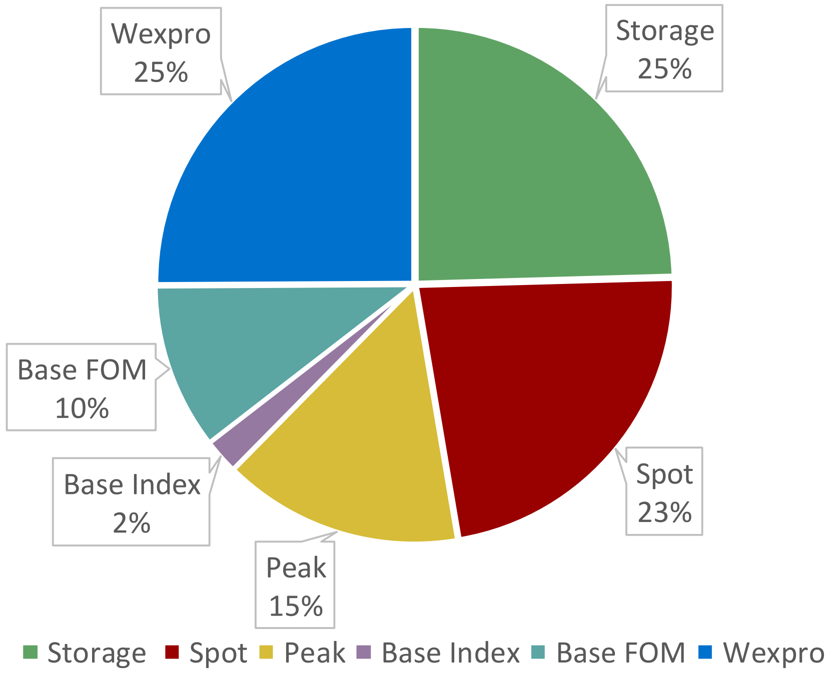


Supply Breakdown
DEUWI

Peak Day



Typical Winter Day (32 Deg/698 MDTH Demand)



* First of Month Index

Types of Supply by Exposure

- DEUWI
  - Spot Gas
    - Daily (Daily Index)
  - RFP Contracts
    - Baseload (FOM Index*)
    - Baseload (Daily Index)
    - Peaking (Daily Index)
  - Storage
    - Clay Basin
    - Leroy
    - Coalville
    - Chalk Creek
    - Spire
  - Wexpro

Market Exposure

Spot Gas – Most Exposed

- Gas purchased at daily index prices to fill supply gaps based on demand.
- Daily spot purchases are subject to daily market price volatility.

RFP Contracts – Somewhat Exposed

- Gas contracts established to ensure adequate supply that can be daily index priced or FOM index priced.
- Daily index priced contracts have the same exposure as spot gas, where FOM index contracts are less susceptible to daily volatility.

Storage – Fall Exposed

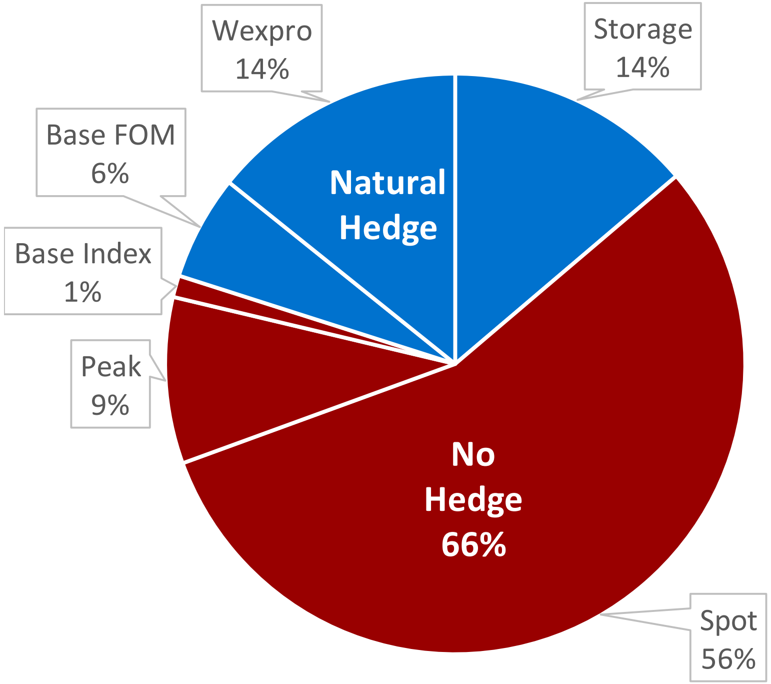
- Gas supply coming from storage is naturally hedged due to the ability to inject during the less volatile months and not needing to inject during high pricing periods.
- Most of DEU’s storage injection also comes from excess Wexpro Gas in the summer.

Wexpro Gas – Least Exposed

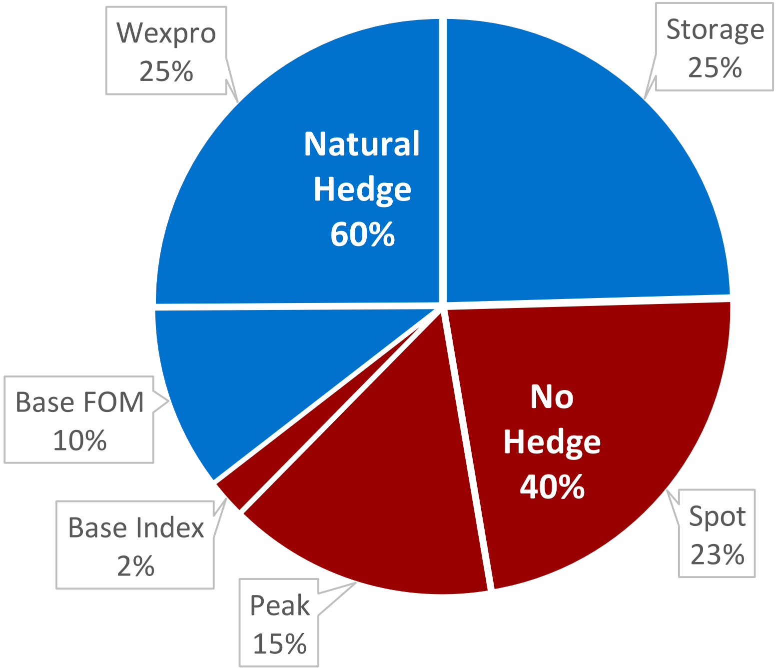
- Cost-of-service gas production, isolated from market driven pricing.
- Pricing is cost based, not market based.

Supply Exposure Current (No Hedge vs. Natural Hedge)
DEUWI

Peak Day



Typical Winter Day (32 Deg/698 MDTH Demand)

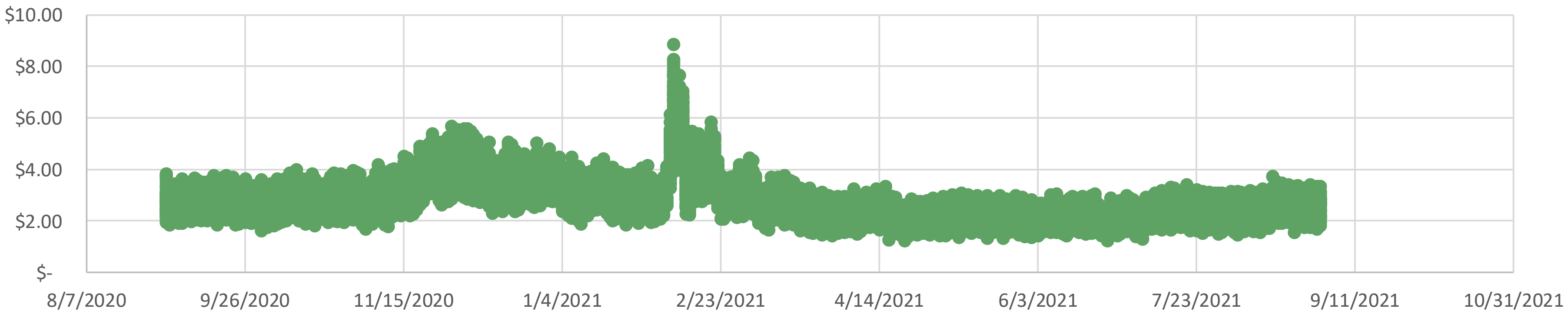


Daily Price Scenarios

50 Randomly Generated Price Scenarios Based on Historical Data

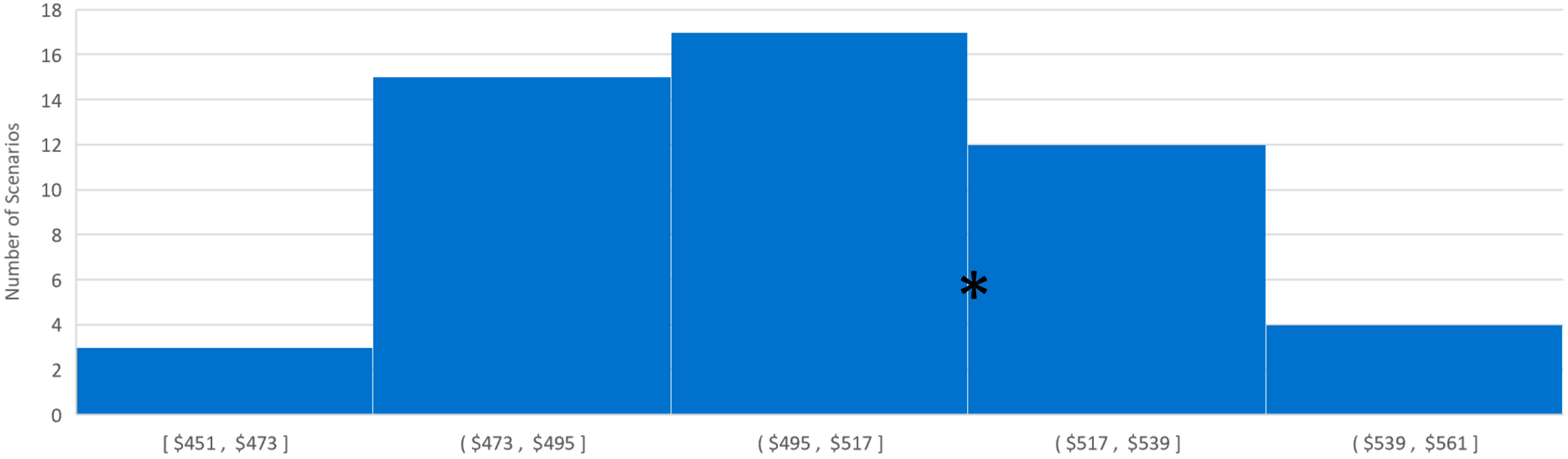
- Each daily price determined based on 5 years of history and a randomly determined weighted average of those 5 years.
- Most daily prices fell between $2 and $4.
- Highest daily spike of about $9
- Longer spikes between $5 and $6

Example table



Price Simulation Cost Results

Frequency of Non-Summer Gas Costs in Millions of $



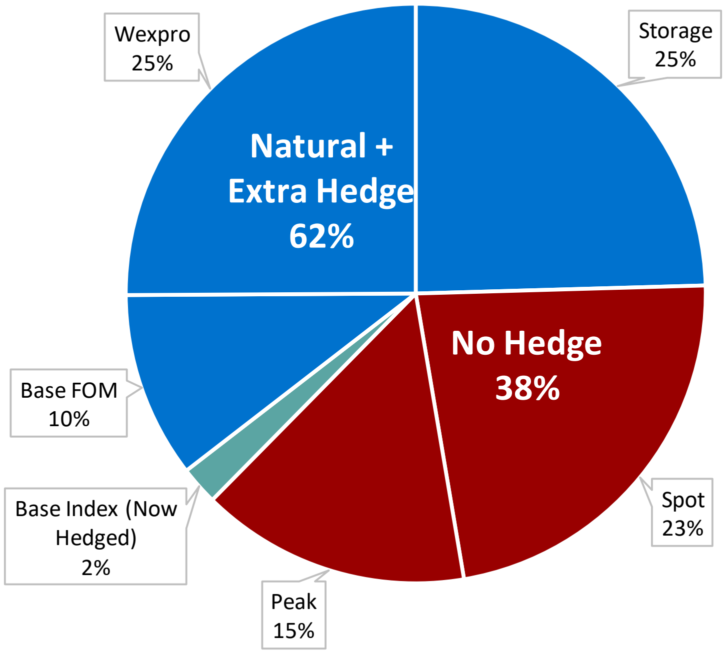
***Forward Gas Prices as of September had Total Non-Summer Gas Costs of $518 Mil**

Supply Exposure Option #1
DEUWI

Potential Scenario #1

- All daily indexed baseload gas purchases are fixed at an agreed upon cost rather than the original contract rates based on daily index prices.
- For winter 2020 this is equal to 15MDth/day.
- If costs vary $1 up or $1 down, Customers have the potential to save/cost approximately $465,000 for an additional 2% hedge for a month with 31 days.
- For all three winter months (Dec – Feb) with an assumed $1 volatility Customers have a potential savings/cost of $1,350,000. This is equal to .26% of September forward predicted non-summer gas costs.

Typical Winter Day (32 Deg/698 MDTH Demand)

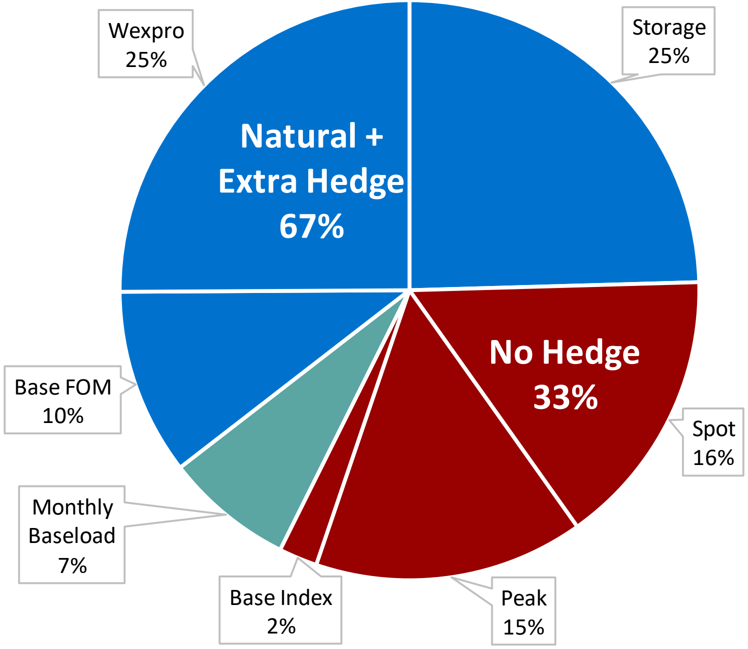


Supply Exposure Option #2
DEUWI

Potential Scenario #2

- Purchase an additional 50MDth/day of monthly baseload for the winter months at a specific fixed cost for each month during bid week.
- If costs vary from a fixed price $1 up or $1 down, Customers have the potential to save/cost $1,550,000 for an additional 7% hedge in a month with 31 days.
- For all three winter months (Dec – Feb) with an assumed $1 volatility Customers have a potential savings/cost of $4,500,000. This is equal to .87% of September forward predicted non-summer gas costs.

Typical Winter Day (32 Deg/698 MDTH Demand)



Supply Exposure Option #3
DEUWI

Potential Scenario #3

- Purchase call options with a price $1 above the current forward prices for Dec-Feb for a quantity of 500MDth in each month. (Approximately an additional 2% hedge.) Total options cost: $293,500

Month	# contracts	volume	Call Option Strike Price	Call Option Premium Price	Call Option Premium Charge
Dec-20	50	500,000	4.25	0.101	$ 50,500
Jan-21	50	500,000	4.4	0.221	$ 110,500
Feb-21	50	500,000	4.35	0.265	$ 132,500

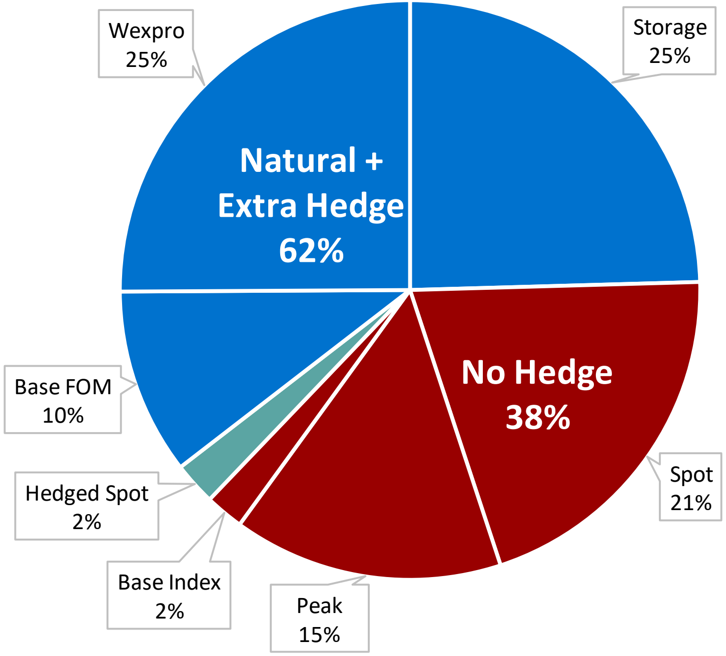
- To break even DEU would need prices equal to the Strike Price + Premium Price. Anything below results in a partial to total loss of the Premium Charge. Anything above results in a gain equal to:

$$\textit{Premium Price} * (\textit{Price at Expiration} - \textit{Strike Price} - \textit{Premium Price})$$

- For all three winter months (Dec – Feb) with an assumed $1 volatility Customers have a potential loss of $293,500 and an infinite potential gain depending on the price at expiration. (Really High = Lots of $)

Month	# contracts	volume	Call Option Settlement Price	Call Option Premium Price	Settlement amount Paid	Total Return
20-Dec	50	500,000	3.25	0.101	$0	$ (50,500.00)
21-Jan	50	500,000	4.5	0.221	$60,500	$ (50,000.00)
21-Feb	50	500,000	5.35	0.265	$367,500	$235,000.00

Typical Winter Day (32 Deg/698 MDTH Demand)

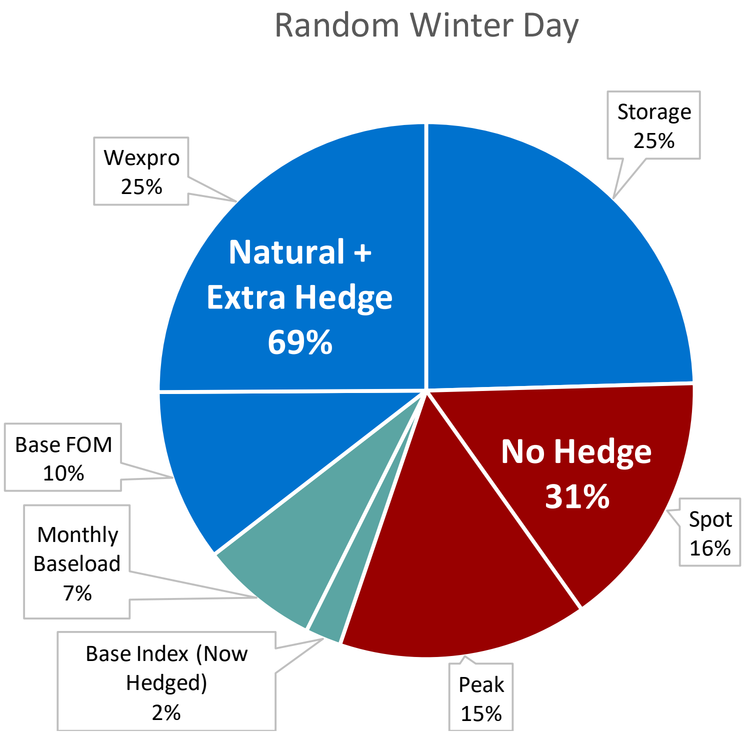


Supply Exposure Option #4
DEUWI

Potential Scenario #4

- Purchase an additional 50 MDth/day of monthly baseload for the winter months at a specific fixed cost for each month during bid week.
- All daily indexed baseload gas purchases are fixed at an agreed upon cost rather than the original contract rates based on daily index prices.
- If costs vary from a fixed price $1 up or $1 down, Customers have the potential to save/cost $2,015,000 for an additional 9% hedge in a month with 31 days.
- For all three winter months (Dec – Feb) with an assumed $1 volatility Customers have a potential savings/cost of $5,850,000. This is equal to 1.13% of September forward predicted non-summer gas costs.

Typical Winter Day (32 Deg/698 MDTH Demand)



Hedging Options

Option #1 – Fix RFP Contract Prices

- Negotiate with suppliers to fix existing baseload contracts (with daily index pricing) to minimize daily price spike risk.
- Con
  - Limited daily index baseload deals will limit overall exposure reduction.
- Pro
  - No changes to existing supply are required.

Option #2 – Fix Spot Prices

- Establish longer-term (monthly) spot purchases at a fixed price, limiting the amount of spot gas to be purchased at daily index prices.
- Cons
  - Limited by the amount of gas that could be used every day during the month.
  - Subject to seasonal (monthly) price volatility.
- Pro
  - Reduces reliance on daily purchase availability

Option #3 – Financial Options

- Purchase strictly financial contracts that mitigate the risk of large price spikes.
- Con
  - Daily financial options aren't very liquid and have high premiums meaning monthly options are likely the needed level of liquidity to be worthwhile.
- Pro
  - Independence to physical gas purchases lessens operational impact.

Final Thoughts

Conclusions

- Given 50 price simulations for non-summer total gas costs DEU saw costs from $451 Million to $561 Million a total range of $110 Million.
- Obviously, there are other potential price simulations and extremes that can happen but the 50 serve as a good baseline.
- The four hypothetical hedging scenarios laid out have the potential to cost us a max of about $5.85 Million which as part of the bigger picture 1.04% - 1.3% to of total non-summer gas costs.
- The scenarios described in the previous slides are just examples of what the Company could potentially do. If desired the Company could hedge a larger or smaller amount depending on what is agreed upon as prudent and necessary.

DEU Recommendation

- Option #4 – A Combination of 1 & 2

Questions?