May 22, 2025

By Electronic Mail

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Re: Velvet-Wood Mine Plan Modification
DOI-BLM-UT-Y020-2025-0018-EA

Dear Mr. Suess:

The Grand Canyon Trust and The Wilderness Society are writing to object to the Department of Interior's use of emergency procedures to rush its review of Anfield Energy's mine plan of operations modification for the Velvet-Wood uranium mine.

As you know, the Department issued a press release last Monday to advertise its pledge to review the mine plan in just 14 days.[1] The cause for haste is the President's declaration of a national energy emergency. To aid its lightning-fast timeline, the Department has invoked "alternative arrangements" for emergency compliance with the National Environmental Policy Act and similar alternative

[1] *See* Ex. 1.

procedures under the Endangered Species Act and National Historic Preservation Act.

Applying those procedures here is unlawful. The relevant regulatory thresholds are not met, and there is no rational basis for concluding that a high-speed review of the mine plan will help alleviate the emergency that has been proclaimed.

What is certain, in contrast, is that the Department in just two weeks cannot satisfy its legal obligations under NEPA, the ESA, and the NHPA for a proposal as complicated and substantial as the mine plan. Though the Department—contrary to its usual procedures—has not made the proposed plan available to the public (even in response to the records request we submitted on May 12), a draft we've unearthed from a Utah state agency runs to over 700 pages. It's evident from a time-constrained review of that document that Velvet-Wood, like any uranium mine, will seriously disrupt the natural setting the mine would take over—with portals and adits, workshops and offices, roads and powerlines, chain-link fences, bulk dump trucks laden with ore, massive fuel tanks, leach fields, water-treatment plants, waste piles, and the other industrial trappings of a mining operation. All that would put water, wildlife, the air, the surrounding landscape, cultural resources, and the like at risk.

Though the risks can be quickly perceived, evaluating how severe they will be and what steps could be taken to minimize them demands more time. Indeed, we don't believe it's possible in just two weeks for the Department to take a "hard look" at those subjects, consult with Tribal nations and with other federal agencies, and make a reasoned decision about how to proceed, as the law requires. Nor is it plausible that the Department can make a reasoned evaluation—as it must—of whether the mine plan satisfies the requirements for public-lands mining operations set out in the applicable regulations.[2]

Eschewing public comments, furthermore, contravenes the Department's obligation to provide, "to the extent practicable" for "public involvement when an environmental assessment is being prepared,"[3] as well as the Federal Land Policy and Management Act's command to give the "public adequate notice and an opportunity to comment upon the formulation of standards and criteria for, and to participate in, the preparation and execution of plans and programs for, and the management of, the public lands."[4]

At root, the Department's slipshod reasoning in invoking the emergency procedures and frantic pace to complete its environmental review fails to heed the basic command imposed by federal law when the Department is confronted with a

[2] *See* 43 C.F.R. Subpart 3809, esp. §§ 3809.401, 3809.420.
[3] 43 C.FR. § 46.305(a).
[4] 43 U.S.C. § 1739(e).

proposal to mine our nation's public lands: thoughtfulness, about whether to let the mine proceed and on what conditions. We consequently urge the Department to abandon its use of the emergency procedures and proceed with a review of the mine plan that allows for informed public comment and that will foster a considered decision by the Department about authorizing that plan.

I. The declaration of an energy emergency is baseless.

The Department issued its emergency procedures[5] in response to Executive Order 14,156, in which the President declared a national energy emergency.[6] Yet that emergency declaration is unfounded.

Of the order's deficiencies, the most prominent is a disparity between the reach of the declared emergency and the prescribed response. What that disparity reveals is that the order and the Department's follow-on procedures are a pretext for boosting favored energy sources, like fossil fuels and nuclear power, while undercutting renewable-energy production.

The subjects the order characterizes as presenting an "emergency" are policy matters of perennial concern: consumer prices, energy supplies and infrastructure, grid reliability, and national security. The order does not describe any sudden or unforeseen circumstances affecting energy markets or national security, and it speaks of the resulting threats to the nation's welfare in unsubstantiated generalities. While the order faults the Biden administration's policies for causing a "dangerous" and "precarious[]" situation, the order does not name the policies in question or describe how they caused an emergency state of affairs.

Taking the order at face value nonetheless, a rational response to the sweeping emergency it declares would involve mobilizing all sources of energy that could enhance our domestic energy needs and promote energy independence. Yet the order defines the terms "energy" and "energy resources" so that none of the order's directives can be applied to promote renewable resources like wind and solar.[7] As a result, the order calls for the use of emergency authorities to subsidize and fast-track the development of only a subset of energy sources, like fossil fuels and nuclear power.

That disparate treatment of conventional and renewable resources is incoherent. There is not a special crisis affecting only conventional energy markets, just as there is no rational basis for excluding renewables if the nation is indeed

[5] *See* Ex. 2; Ex. 3; Ex. 4.
[6] Exec. Order No. 14,156, 90 Fed. Reg. 8,433 (Jan. 20, 2025) ("EO 14,156").
[7] *See* EO 14,156 § 8(a) (defining "energy" or "energy resources" to mean "crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals….").

confronting a system-wide energy crisis. For the past six years in a row, the United States has produced more crude oil than any country in history.[8] Gasoline prices are modest.[9] So are oil prices.[10] Natural gas prices are low.[11] We are exporting vast amounts of surplus oil and gas.[12] And we lead the world in nuclear[13] and geothermal power production.[14]

Meanwhile, renewable resources like wind and solar are generally cost competitive with conventional sources. Wind and solar can help make our grid more reliable, though adjustments in managing the grid are needed to adapt to their intermittent nature.[15] By the same token, conventional resources are not free of reliability problems, like serious disruptions in the delivery of natural gas in the winter.[16] And renewables help diversify our nation's energy supplies, promoting energy independence.

By discriminating against renewables like wind and solar, EO 14,156 signals that the emergency it declares has no underpinning and that the order's purpose is merely to promote fossil fuels, nuclear, and other conventional energy sources. And the Department's reliance on that order for invoking emergency authorities under NEPA, the ESA, and the NHPA has set the Department on a path toward violating the law.

II. The emergency procedures are contrary to the applicable regulations.

The mere declaration by the President of a national energy emergency is not by itself a sufficient legal basis for invoking the regulatory authorities on which the emergency procedures rely. Each of the regulations allowing for departures during emergencies from the normal process for complying with NEPA, the ESA, and the

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[8] *See* Ex. 5.
[9] *See* Ex. 6 (revealing comparable inflation-adjusted gasoline prices in 2023 as in the 1950s and 1960s).
[10] *See, e.g.*, Ex. 7 (showing roughly comparable prices today and twenty years ago).
[11] *See, e.g.*, Ex. 8 (showing current spot prices in line with historically low levels since the 1990s).
[12] *See* Ex. 9.
[13] *See* Ex. 10 ("The USA is the world's largest producer of nuclear power, accounting for about 30% of worldwide generation of nuclear electricity.")
[14] *See* Ex. 11 ("The United States leads the world in geothermal electricity-generating capacity—just over 4 gigawatts.").
[15] *See, e.g.*, Ex. 12 at 12–14 ("Summer 2024 demonstrated the combined ability of solar and storage to provide valuable capacity during summer peaks in diverse regions across the country, including Texas, California, and New England"); Ex. 13; Ex. 14.
[16] *See, e.g.*, Ex. 15 at 8 (reporting that "the weighted equivalent forced-outage rates (WEFOR) of baseload coal and cycled natural gas units remained high in 2023 …, remaining the primary drivers for the high conventional generator outage rates."); Ex. 16 at 7 ("The reliability of conventional generation is significantly challenged by more frequent extreme weather, high-demand conditions, and a changing resource mix, resulting in higher overall outage rates and surpassing transmission in their contribution to major load loss events.").

NHPA applies only in situations not present here: when there are sudden, unforeseen, or urgent circumstances that present serious or dangerous threats requiring an immediate response.[17]

The Department's NEPA emergency-response rule, for example, may be invoked when the Department cannot follow the usual NEPA process before taking "urgently needed actions" in response to an emergency.[18] When the Department adopted the rule, it explained that it was using the term "emergency" in accordance with its "common usage," citing dictionaries whose definitions all describe emergencies as "unforeseen," "sudden," or "urgent" situations that demand "immediate" action.[19]

The Department's ESA regulation governing emergencies similarly applies only to "situations involving acts of God, disasters, casualties, national defense or security emergencies, etc."[20] And the relevant NHPA regulation authorizes alternative procedures for an "essential and immediate response" to a "disaster or emergency declared by the President, a tribal government, or the Governor of a State or another immediate threat to life or property."[21]

Past use of these regulatory authorities illustrates the kinds of circumstances they reach: urgent actions responding to hurricanes, wildfires, floods, war, the imminent extinction of a species, toxic spills, failing bridges and dams, nuclear proliferation, and the like.[22]

Here, in contrast, the Department has invoked its emergency procedures not in response to an urgent and dangerous situation, but as a means of pursuing partisan energy policies. The Department has given no reason separate from EO 14,156 for issuing the emergency procedures.[23] And as explained above, EO 14,156 does not

[17] 43 C.F.R. § 46.150 (authorizing alternative NEPA procedures when an "emergency exists that makes it necessary to take urgently needed actions before preparing a NEPA analysis and documentation in accordance with" the Department's regulations); 50 C.F.R. § 402.05 (allowing alternative ESA procedures in "situations involving acts of God, disasters, casualties, national defense or security emergencies, etc."); 36 C.F.R. § 800.12 (addressing emergency NHPA procedures when responding to a "disaster or emergency declared by the President, a tribal government, or the Governor of a State or another immediate threat to life or property.").
[18] 43 C.F.R. § 46.150.
[19] "Implementation of the National Environmental Policy Act (NEPA) of 1969," 73 Fed. Reg. 61,292, 61,301 (Oct. 15, 2008) (citing dictionary definitions of the word "emergency" to involve "unforeseen" and "sudden" circumstances requiring an "urgent" or "immediate" response).
[20] 50 C.F.R. § 402.05.
[21] 36 C.F.R. § 800.12(a), (b).
[22] *See* Ex. 17; *Miccosukee Tribe of Indians v. United States*, 420 F. Supp. 2d 1324, 1329–30 (S.D. Fla. 2006); *Valley Citizens for a Safe Env't v. Vest*, 1991 WL 330963 (D. Mass. May 30, 1991); *Damascus Citizens for Sustainability v. Duffy*, 2025 WL 1139281, *7–8 (Apr. 15, 2025).
[23] *See* Ex. 2; Ex. 3; Ex. 4.

supply a lawful basis for invoking the relevant NEPA, ESA, and NHPA emergency regulations, for that order describes no developments that are sudden, urgent, or unforeseen, and that present serious or dangerous threats requiring an immediate response.

Like EO 14,156, furthermore, the emergency procedures are circumscribed so that only fossil-fuel, nuclear, and a few other energy-related developments can be fast-tracked in response to the declared "emergency." Wind, solar, and other renewables are excluded, a disparity that, again, is irrational on its face if the Department is to be believed that urgent action is necessary for answering a serious energy-supply or national-security threat.

What is more, the Department has crafted the emergency procedures so that project proponents must opt-in as a precondition for applying the procedures.[24] The upshot is that the only basis for rushing a project's review is an energy producer's preference for expedited treatment, and not a case-by-case evaluation of how a particular project might alleviate the claimed emergency situation. What that reveals, again, is that the emergency declaration is a pretense for extending favored treatment to conventional energy projects.

At bottom, the Department has failed to provide a rational explanation for invoking the emergency procedures, and the mechanics of the procedures themselves belie the very emergency the Department has declared. Use of the procedures is accordingly unlawful under the applicable NEPA, ESA, and NHPA regulations.

III. Application of the emergency procedures to the Velvet-Wood mine plan is arbitrary and capricious.

Even were there a bona fide national energy emergency, it is irrational for the Department to apply emergency procedures to hasten the review of the Velvet-Wood mine plan, for swift approval of that plan will not alleviate the alleged "emergency." This is so for two main reasons.

First, even if the Department approves the plan in just two weeks, the mine will take many months, or even years, to begin producing uranium, provided everything goes to plan. The company must first secure a host of permits from state and federal agencies. These include, at a minimum, a large mine permit amendment, a Utah Pollutant Discharge Elimination System permit, a state ground water discharge permit, a state air quality permit, state permits to construct groundwater wells, the transfer of water rights, a county septic system authorization, a federal permit from the Mine Safety and Health Administration, and possibly, a state source

[24] Ex. 2 at 1; Ex. 3 at 1; Ex. 4 at 2.

material license for the management of radioactive materials.[25] And even if Anfield secures all required permits for the mine, the company anticipates that it will take more than a year to prepare the site before it can begin mining for uranium ore.[26] So far as we can discern, if Anfield achieves that objective, it would be a first for the company, which appears for at least the past decade to have only held uranium and vanadium assets without producing anything.[27]

Second, once the mine is operational, the company forecasts recovering only a small amount of uranium. Based on a 2023 Preliminary Economic Assessment that Anfield prepared for Velvet-Wood, there is no estimate of any "mineral reserves" at the mine, which refers to economically recoverable uranium.[28] Only 897,800 tons of non-economic, but potentially recoverable, "mineral resources" are projected to be present, equating to about 5 million pounds of uranium that conceivably might be produced over the eight-year life of the mine.[29] That's about 625,000 pounds of uranium per year—which is just over 1% of the average amount purchased annually for the past decade to keep the U.S. nuclear reactor fleet running.[30] And even that small amount of production capacity is speculative, for the data used to support that resource estimate have not been verified and are unsupported by any field testing.

To further put Velvet-Wood's potential production capacity in context, two currently operating uranium mines in Canada, the MacArthur River and Cigar Lake mines owned by Cameco, each produced roughly 20 million pounds of uranium ore last year alone.[31] At that rate, these two mines could satisfy nearly all the United States' annual nuclear-fuel demand. Velvet-Wood, in contrast, will not make any material difference in the domestic market for supplying nuclear-powered generators.

All told, reviewing, and even approving, the Velvet-Wood mine plan at breakneck speed will not help bring some crisis under control, avert some urgent danger, or mollify threats to life or property. Applying the emergency procedures here is therefore arbitrary and capricious.

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[25] Ex. 18 at 116, 118, Table 20.1.
[26] Ex. 19 at PDF p. 34, Fig. 1.
[27] Ex. 20 (describing Velvet-Wood as Anfield's "most advanced" asset, though it has not operated); *see also* Ex. 21 (investor presentation describing Anfield's assets but no past production history).
[28] *See* Ex. 18 at PDF pp. 8, 15, 18.
[29] *Id.* at PDF p. 76, Table 14.12; Ex. 19 at PDF p. 34, Fig. 1 (projecting an 8-year operating period for the mine, assuming that market conditions allow for constant production).
[30] *See* Ex. 22 at Table S1a (reporting average annual uranium purchases from 2014 to 2023 of 48 million pounds).
[31] *See* Ex. 23 at 17.

Applying the emergency procedures to review and consult about the Velvet-Wood mine plan is contrary to law. We urge the Department to abandon that course and to instead provide enough time to study the plan with care, to consult with Native nations with respect and deliberation, and to allow the public to provide educated input.

Very truly yours,

Aaron M. Paul
Staff Attorney
Grand Canyon Trust

Ronni Flannery
Senior Staff Attorney
The Wilderness Society

cc: Emilee Helton, Bureau of Land Management
Jill Stephenson, Bureau of Land Management
Tina Marian, Bureau of Land Management

Exhibit List

Exhibit 1	U.S. Department of the Interior, "Interior expedites permitting for critical energy project to address national energy emergency" (May 12, 2025).
Exhibit 2	U.S. Department of the Interior, "Alternative Arrangements for NEPA Compliance" (Apr. 23, 2025).
Exhibit 3	U.S. Department of the Interior, "Alternative Procedures for Informal Section 7 Consultation" (Apr. 23, 2025).
Exhibit 4	U.S. Department of the Interior, "Emergency Process for Section 106 Compliance" (Apr. 23, 2025).
Exhibit 5	U.S. Energy Information Administration, "United States produces more crude oil than any country, ever" (Mar. 11, 2024).
Exhibit 6	U.S. Department of Energy, Alternative Fuels Data Center, "Average Annual Retail Fuel Price of Gasoline" (Jan. 2024).
Exhibit 7	U.S. Energy Information Administration, "U.S. Crude Oil First Purchase Price" (May 1, 2025).
Exhibit 8	U.S. Energy Information Administration, "Natural Gas: Henry Hub Natural Gas Spot Price" (May 21, 2025).
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Exhibit 10	World Nuclear Association, "Nuclear Power in the USA" (Aug. 27, 2024).
Exhibit 11	U.S. Department of Energy, "Electricity Generation" (May 22, 2025).
Exhibit 12	National Renewable Energy Lab, "How the U.S. Power Grid Kept the Lights on in Summer 2024" (Nov. 2024).
Exhibit 13	National Renewable Energy Lab, "Active Power Controls from Wind Power: Bridging the Gaps" (Jan. 2014) (excerpts).
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Exhibit 15	N. Am. Electric Reliability Corp., "2024 State of Reliability Overview" (June 2024)
Exhibit 16	N. Am. Electric Reliability Corp., "2023 State of Reliability Overview" (June 2023)

Exhibit 17	Council on Environmental Quality, "Alternative Arrangements Pursuant to 40 CFR Section 1506.11 – Emergencies" (May 2019).
Exhibit 18	Beahm, Douglas L., et al., "The Shootaring Canyon Mill and Velvet-Wood and Slick Rock Uranium Projects, Preliminary Economic Assessment, National Instrument 43-101" (May 6, 2023).
Exhibit 19	BRS, Inc. Engineering, Letter from C. Warren to W. Western re: Initial Review of Revised Notice of Intention to Commence Large Mining Operations, Anfield Resources Holding Corporation, Velvet Mine, M/037/0040, Task #23218, San Juan County, Utah (Mar. 31, 2025) (excerpts).
Exhibit 20	Anfield Energy, "Velvet Wood Project" (May 22, 2025).
Exhibit 21	Anfield Energy, "Pursuit of Hub-and-Spoke Uranium & Vanadium Production Strategy in the United States" (Sep. 2023).
Exhibit 22	U.S. Energy Information Administration, "Uranium Marketing Annual Report" (June 2024).
Exhibit 23	Cameco Corp., "2024 Annual Report" (Feb. 20, 2025) (excerpts).

Exhibit 1

Interior expedites permitting for critical energy project to address national energy emergency

Organization:
Bureau of Land Management
Media Contact:
Interior_Press@ios.doi.gov
Interior_Press@ios.doi.gov
May 12, 2025

The Department of the Interior announced today the expedited permitting review of a major energy project—the Velvet-Wood mine in Utah—under its newly established emergency procedures. As part of a strategic response to the national energy emergency declared by President Donald J. Trump on January 20, 2025, the project will undergo an accelerated environmental review by the Bureau of Land Management, with a completion timeline of 14 days. The expedited review is expected to significantly contribute to meeting urgent energy demands and addressing key threats to national energy security.

“America is facing an alarming energy emergency because of the prior administration’s Climate Extremist policies. President Trump and his administration are responding with speed and strength to solve this crisis,” said Secretary of the Interior Doug Burgum. “The expedited mining project review represents exactly the kind of decisive action we need to secure our energy future. By cutting needless delays, we’re supporting good-paying American jobs while strengthening our national security and putting the country on a path to true energy independence.”

If approved, the Velvet-Wood mine project in San Juan County, Utah, would produce uranium and vanadium by accessing the old Velvet Mine workings and developing the Velvet-Wood mineralization. The plan would result in only three acres of new surface disturbance given the proposed underground mining plan and the existing surface disturbance from the old Velvet mine. Anfield also owns the Shootaring Canyon uranium mill in Utah, which the company intends to restart. That mill would convert uranium ore into uranium concentrate, helping reduce America’s reliance on imported uranium concentrate.

Commercial uses of uranium include fuel for civilian nuclear reactors, as well as various uses in medical applications. Uranium is also used for fuel in U.S. Navy nuclear reactors, such as on the Virginia-class attack submarine, and in the production of tritium, which is required for nuclear weapons. Additionally, vanadium has important uses, namely as a strengthening agent in steel production. It is also used in titanium aerospace alloys in both commercial and military aircraft.

For both uranium and vanadium, the United States is dangerously reliant on foreign imports to meet its demand. Under the Biden administration in 2023, US nuclear generators **relied 99% on imported uranium concentrate**, including from sources in Russia, Kazakhstan, and Uzbekistan. In 2024, the United States relied on foreign imports for nearly half of its domestic consumption of vanadium, and China, Russia, South Africa, and Brazil produced **nearly 100% of the world’s mined vanadium**.

As the President’s national energy emergency declaration notes, “Our Nation’s current inadequate development of domestic energy resources [including both uranium and vanadium] leaves us vulnerable to hostile foreign actors and poses an imminent and growing threat to the United States’ prosperity and national security.”

Under leadership from Secretary of the Interior Doug Burgum, the Bureau of Land Management supports the nation’s energy independence by overseeing the extraction of critical minerals needed for technologies like electric grids and defense applications and by authorizing the development of traditional energy production, such as oil, gas, and coal. By managing public lands for responsible mineral extraction, the BLM ensures a stable supply of these essential resources. Through permitting, land management, and environmental oversight, the BLM helps reduce reliance on foreign minerals, bolstering the nation's energy security and supporting the continued operation of key industries.

“Today’s actions will greatly accelerate the permitting review of the Velvet-Wood,” said Acting Assistant Secretary for Land and Minerals Management Adam Suess. “By fast-tracking the review process for the project, we are driving American Energy Dominance and ensuring our nation’s energy security.”

The Department is utilizing emergency authorities under existing regulations for the National Environmental Policy Act, National Historic Preservation Act and the Endangered Species Act. Interior has prepared a list of frequently asked questions pertaining to the emergency procedures. Project proponents interested in requesting emergency coverage should contact their regular points of contact at the pertinent field, district, or state office.

The BLM manages more than 245 million acres of public land located primarily in 12 western states, including Alaska, on behalf of the American people. The BLM also administers 700 million acres of sub-surface mineral estate throughout the nation. Our mission is to sustain the health, diversity, and productivity of America’s public lands for the use and enjoyment of present and future generations.

Exhibit 2

ALTERNATIVE ARRANGEMENTS FOR NEPA COMPLIANCE

Alternative Arrangements for Compliance with the National Environmental Policy Act amid the National Energy Emergency

On January 20, 2025, President Donald J. Trump declared a national energy emergency and directed the heads of executive departments and agencies, including the Secretary of the Interior, to "identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands" (Sec. 2(a), Executive Order (EO) 14156, titled "Declaring a National Energy Emergency"). The definition of energy resources includes "crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. § 1606(a)(3)" (section 8(a), EO 14156).

During an emergency, a Department of the Interior (Department) Responsible Official—which includes the Acting Assistant Secretary – Land and Minerals Management—can adopt alternative arrangements to comply with the National Environmental Policy Act (NEPA) before taking urgently needed actions (43 CFR 46.150). These alternative arrangements apply both to actions not likely to have significant environmental impacts (43 CFR 46.150(c)) *and* to actions likely to have significant environmental impacts (43 CFR 46.150(d)). The Acting Assistant Secretary – Land and Minerals Management has coordinated with the Office of Environmental Policy and Compliance and appropriate Bureau headquarters, and consulted with the Council on Environmental Quality (CEQ) about alternative arrangements for NEPA compliance concerning energy projects that respond to the energy emergency (43 CFR 46.150(c)-(d)). CEQ authorized the use of these alternative arrangements for projects that respond to the national energy emergency on April 23, 2025. The designee of the Acting Assistant Secretary – Policy, Management and Budget has approved the following alternative arrangements (43 CFR 46.150(c)-(d)), which have been adopted by the Acting Assistant Secretary – Land and Minerals Management:

1. The only energy-related projects eligible for alternative arrangements for NEPA compliance are those projects:
   a. that seek to identify, lease, site, produce, transport, refine, or generate energy resources as defined in section 8(a) of EO 14156; and
   b. for which the project applicant(s) have submitted plans of operations, applications for permits to drill, or other applications.

2. The project applicant must affirm in writing that they want the review of their project to be covered by the alternative arrangements for NEPA compliance. (See Attachment 1)

3. The Responsible Official evaluating the application will prepare a focused, concise, and timely NEPA document in accordance with the following process:
   a. For projects not likely to have significant environmental impacts, the Responsible Official will prepare a focused, concise, and timely environmental assessment

addressing the purpose and need for the proposed action, alternatives, mitigation measures, and a brief description of environmental effects. The environmental assessment should be prepared within approximately 14 days of receiving a complete application. If the environmental assessment supports a finding of no significant impact, documentation of such finding should be prepared concurrently within the same period of approximately 14 days. The Responsible Official will publish the environmental assessment and finding of no significant impact on a public website. The Responsible Official is not required to seek public comment prior to finalizing the environmental assessment, finding of no significant impact, and any decision.

b. For projects likely to have significant environmental impacts, the Responsible Official will follow the alternative arrangements outlined in CEQ's letter dated April 23, 2025, also described here. The Responsible Official will publish a notice of intent to prepare an environmental impact statement on a public website soliciting written comments and announcing a public meeting to be held during preparation of the environmental impact statement. The Responsible Official will, in his discretion, determine the duration of the written comment period based on the nature of the action and the urgency of the emergency response, and the Department anticipates that most comment periods will be approximately 10 days. The public meeting may be virtual or in person, at the discretion of the Responsible Official, considering the nature of the action and the likely effects. The Responsible Official will prepare a focused, concise, and timely environmental impact statement addressing the purpose and need for the proposed action, alternatives, and a brief description of environmental effects in accordance with 43 CFR 46.415(a)-(b). The environmental impact statement should be prepared within approximately 28 days of publishing the notice of intent to prepare an environmental impact statement. The Responsible Official will publish the environmental impact statement on a public website and file it with the Environmental Protection Agency. The Responsible Official is not required to publish a draft environmental impact statement prior to finalizing the environmental impact statement and any record of decision.

4. Only the Assistant Secretary – Land and Minerals Management, Deputy Secretary of the Interior, Secretary of the Interior, their acting equivalents, or those officials exercising the delegated authority of these positions may approve coverage of an application by alternative arrangements for NEPA compliance, and only those officials may issue a decision to approve an application or otherwise take action covered by such alternative arrangements. Any approval must be made in compliance with other applicable statutes, such as the Endangered Species Act and National Historic Preservation Act. Any approval must also document how the action addresses the national energy emergency.

5. The project applicant must agree to:

   a. operate in accordance with the application approved in 4;

   b. take measures to mitigate reasonably foreseeable significant adverse effects on the quality of the human environment; and

c. abide by applicable Federal (e.g., Clean Water Act, Clean Air Act), State, and local environmental laws. (See Attachment 1)

During the national energy emergency, these alternative arrangements for NEPA compliance for energy-related projects (as defined in 1(a)–(b) above) shall remain applicable unless superseded by subsequent alternative arrangements for NEPA compliance. If 43 CFR 46.150 is rescinded or revised during the national energy emergency, these alternative arrangements for NEPA compliance for energy-related projects (as defined in 1(a)–(b) above) shall remain applicable unless explicitly superseded by interim or final guidance or regulations.

This document and the environmental documents prepared under these procedures satisfy 43 CFR 46.150(b), which requires that the Responsible Official "document in writing the determination that an emergency exists and describe the responsive action(s) taken at the time the emergency exists."

Adam Suess,
Acting Assistant Secretary – Land and Minerals Management.

Eva Vrana,
Deputy Assistant Secretary – Policy, Management and Budget; Designee of the Assistant Secretary – Policy, Management and Budget

Karen Budd-Falen,
Acting Deputy Secretary.

ATTACHMENT 1

Request for Energy Project Coverage under the Department of the Interior's Alternative Arrangements for Compliance with the National Environmental Policy Act

ATTN: [APPROPRIATE DISTRICT/STATE/REGIONAL OFFICE CONTACTS OF THE FEDERAL ACTION AGENCY]

Company name: [INSERT COMPANY NAME]
Project name: [INSERT COMPANY NAME]
Project city, state: [INSERT INFORMATION]
Lead agency: [INSERT LEAD AGENCY NAME]

Our company, [INSERT COMPANY NAME], requests that the Department of the Interior apply its alternative arrangements for complying with the National Environmental Policy Act when evaluating [INSERT PROJECT NAME] amid the national energy emergency. (See "Alternative Arrangements for Compliance with the National Environmental Policy Act amid the National Energy Emergency," April 23, 2025.)

The latest version of the [proposed plan of operation or other application] for [INSERT PROJECT NAME] is attached. [ATTACH PLAN OF OPERATION OR OTHER APPLICATION]

If the attached [plan of operation or other application] is approved, our company agrees to the following, pursuant to the Department's "Alternative Arrangements for Compliance with the National Environmental Policy Act amid the national energy emergency"; [INSERT COMPANY NAME] shall:

1. operate in accordance with the approved [plan of operations or other application];
2. take measures to mitigate reasonably foreseeable significant adverse effects on the quality of the human environment; and
3. abide by applicable federal (e.g., Clean Water Act, Clean Air Act), state, and local environmental laws.

____________________________________ _______________
Signature Date

____
Name

____
Title

Exhibit 3

ALTERNATIVE PROCEDURES FOR INFORMAL SECTION 7 CONSULTATION

Alternative Procedures for Informal, Expedited Consultation under Section 7 of the Endangered Species Act for Energy Projects amid the National Energy Emergency

On January 20, 2025, President Donald J. Trump declared a national energy emergency and directed the heads of executive departments and agencies, including the Secretary of the Interior, to "identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands" (Sec. 2(a), Executive Order (EO)14156, titled "Declaring a National Energy Emergency"). The definition of energy resources includes "crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. § 1606(a)(3)" (section 8(a), EO 14156).

During a national emergency, the Department of the Interior can adopt alternative procedures for informal, expedited consultation to comply with section 7(a)-(d) of the Endangered Species Act (ESA) (50 CFR 402.05). Paul Souza, who is the Regional Director exercising the delegated authority of the U.S. Fish and Wildlife Service (FWS) Director, has determined that the following alternative procedures are consistent with the requirements of section 7(a)-(d) of the ESA (50 CFR 402.05(a)):

1. The only projects eligible for these particular alternative procedures for the informal, expedited section 7 consultation are those projects:
    1. that seek to identify, lease, develop, produce, transport, refine, or generate energy resources as defined in section 8(a) of EO 14156; and
    2. for which the project applicant(s) have submitted plans of operations, applications for permits to drill, and other applications.

2. The project applicants must affirm in writing that they want their project covered by the alternative procedures for informal, expedited section 7 consultation. (See Attachment 1)

3. The Secretary of the Interior, the Deputy Secretary of the Interior, the appropriate Assistant Secretary, their acting equivalents, or those officials exercising the delegated authority of these positions must approve coverage of the project under the alternative procedures for informal, expedited section 7 consultation.

4. The alternative procedures are the following:
    a. The Federal action agency shall inform FWS about the proposed action and decision to use the alternative consultation procedures due to the national energy emergency.
    b. The Federal action agency coordinates with FWS in accordance with 50 CFR 402.05(a) and proceeds with the proposed action if the necessary requirements of other departments and agencies are met.

5. As soon as practicable under the circumstances, following termination or expiration of the national energy emergency, the Federal action agency shall follow 50 CFR 402.05(b) and provide the information necessary to initiate consultation. FWS shall evaluate the information and deliver either a biological opinion or letter of concurrence to the Federal action agency, as appropriate, and in accordance with the timeframes set forth in the ESA section 7 implementing regulations at 50 CFR part 402.

During the national energy emergency, these alternative procedures for informal, expedited section 7 consultation shall remain applicable for these particular projects unless superseded by subsequent alternative procedures for informal, expedited section 7 consultation. If 50 CFR 402.05 is rescinded or revised during the national energy emergency, these alternative procedures for informal, expedited section 7 consultation shall remain applicable unless explicitly superseded by interim or final guidance or regulations.

Adam Suess,
Acting Assistant Secretary – Land and Minerals Management

ATTACHMENT 1

Request for Energy Project Coverage under the Department of the Interior's Alternative Procedures for Informal, Expedited Consultation under Section 7 of the Endangered Species Act for Energy Projects amid the National Energy Emergency

ATTN: [APPROPRIATE DISTRICT/STATE/REGIONAL OFFICE CONTACTS OF THE FEDERAL ACTION AGENCY]
CC: Paul Souza, Exercising the Delegated Authority of the Director of the Fish and Wildlife Service

Company name: [INSERT COMPANY NAME]
Project name: [INSERT COMPANY NAME]
Project city, state: [INSERT INFORMATION]
Lead agency: [INSERT LEAD AGENCY NAME]

Our company, [INSERT COMPANY NAME], requests that [INSERT PROJECT NAME] is covered by the Department of the Interior's alternative procedures for informal, expedited section 7 consultation under the Endangered Species Act amid the national energy emergency.

The latest version of the [proposed plan of operation or other application] for [INSERT PROJECT NAME] is attached. [ATTACH PLAN OF OPERATION OR OTHER APPLICATION]

____ ________________
Signature Date

____
Name

____
Title

Exhibit 4

EMERGENCY PROCESS FOR SECTION 106 COMPLIANCE

Using the Emergency Provisions to Comply with Section 106 of the National Historic Preservation Act in Response to the National Energy Emergency

On January 20, 2025, President Donald J. Trump declared a national energy emergency and directed the heads of executive departments and agencies, including the Secretary of the Interior, to "identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands" (Sec. 2(a), Executive Order (EO) 14156, titled "Declaring a National Energy Emergency"). The definition of "energy resources" in the declaration includes "crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. § 1606(a)(3)" (section 8(a), EO 14156).

The Advisory Council on Historic Preservation's (ACHP) regulations that implement section 106 of the National Historic Preservation Act (NHPA) expressly recognize the need for alternative procedures for compliance concerning proposed undertakings that address emergency situations, including when the President declares an emergency (36 C.F.R. § 800.12(a)). In the case of an emergency, the regulations offer several ways to comply with the requirements of section 106 of the NHPA:

(1) development of formal emergency procedures, 36 C.F.R. § 800.12(a);

(2) use of an existing Programmatic Agreement (PA) that includes specific provisions covering emergency procedures, 36 C.F.R. § 800.12(b)(1); or

(3) an ad hoc process for undertakings responding to an emergency declaration when there is no formal emergency procedure or an applicable PA, 36 C.F.R. § 800.12(b)(2).

Using these provisions, as appropriate, involves complying with certain minimal requirements, but each provision allows for expedited approval of undertakings that respond to the emergency.

Given the national energy emergency declaration in EO 14156, the Department of the Interior (Department) intends to use the emergency provisions in 36 C.F.R. § 800.12 to satisfy compliance with section 106 for those undertakings that respond to the National Energy Emergency.[1] As described below, the Department has identified an initial criteria of projects that would facilitate an essential and immediate response to the declared national energy emergency. The Department further sets forth below the steps that the appropriate Interior Bureaus will undertake to meet the emergency provisions covered under 36 C.F.R. § 800.12(b)(1) or (2). Currently, the Department does not have formal emergency procedures approved by the ACHP that are applicable to the National Energy Emergency consistent with 36 C.F.R. § 800.12(a).

[1] On February 25, 2025, the ACHP issued guidance on the use of the emergency provisions in the regulations (36 C.F.R. § 800.12) implementing Section 106 of the NHPA relating to EO 14156. The ACHP's guidance implicitly interprets its Section 106 regulations regarding emergencies, identified in the regulations as a "disaster or emergency declared by the President . . ., or another immediate threat to life or property," 36 CFR § 800.12(b), as applying to the energy emergency declaration. The guidance also extends the time in which an agency may use the emergency provisions for an applicable undertaking relating to EO 14156 from 30 days to a period coinciding with the duration of the emergency declaration.

However, the Department, or Interior Bureaus, will consider the utility of developing such procedures.

This document serves as notice to applicants for projects related to "energy resources" as defined by EO 14156, as well as to the ACHP, all State Historic Preservation Offices (SHPOs), Tribal Historic Preservation Offices (THPOs), and Indian tribes, that the Department will rely on the emergency provisions set forth at 36 C.F.R. § 800.12(b)(2) to satisfy its obligations under section 106 of the NHPA as follows:

1. The only projects eligible for alternate procedures for compliance with section 106 of the NHPA will be those projects:
    a. that seek to identify, lease, develop, produce, transport, refine, or generate energy resources, as defined in section 8(a) of EO 14156; and
    b. for which the project applicant(s) have submitted plans of operations, applications for permits to drill, or other applications.
2. The energy project applicants must affirm in writing to the Responsible Official(s) that they
    a. want to proceed under the alternative procedures; and
    b. will implement, to the extent prudent and feasible, measures that avoid or minimize harm to historic properties.
3. The relevant Responsible Official(s) are responsible for notifying the ACHP, relevant SHPOs, THPOs, and Indian tribes of the specific energy project(s) for which they intend to use the emergency section 106 alternative procedures as provided in 36 C.F.R. § 800.12(b)(2) and will invite comments within seven days of the notice.

For those eligible projects under the Bureau of Land Management's (BLM) jurisdiction that qualify to use the specific emergency procedures included in an existing Programmatic Agreement (or State Protocol Agreement), BLM will follow those existing emergency procedures as authorized under 36 C.F.R. § 800.12(b)(1).

During the national energy emergency, these alternative procedures described herein for energy-related projects will remain applicable unless superseded by subsequent alternative procedures for section 106 compliance. If the ACHP rescinds or revises the section 106 regulations or the emergency provisions during the national energy emergency, the Department will continue to rely on the alternative procedures that have already been used to demonstrate compliance with section 106 of the NHPA unless explicitly superseded by interim or final guidance or regulations. Following termination or expiration of the national energy emergency, the Department will not use the emergency alternative procedures for section 106 compliance and instead will comply with the standard section 106 process.

Adam Suess,
Acting Assistant Secretary – Land and Minerals Management.

ATTACHMENT 1

Request to Use the Department of the Interior's Alternative Procedures for Compliance with Section 106 of the National Historic Preservation Act for an Energy Resources Project during the National Energy Emergency

ATTN: [APPROPRIATE DISTRICT/STATE/REGIONAL OFFICE CONTACTS OF THE FEDERAL ACTION AGENCY]

Company name: [INSERT COMPANY NAME]
Project name: [INSERT COMPANY NAME]
Project city, state: [INSERT INFORMATION]
Lead agency: [INSERT LEAD AGENCY NAME]

Our company, [INSERT COMPANY NAME], requests to use the Department of the Interior's emergency provisions for [INSERT PROJECT NAME] to comply with section 106 of the National Historic Preservation Act because it will provide an essential and immediate response to the national energy emergency, as declared in Executive Order 14156.

The latest version of the [proposed plan of operation or other application] is attached. [ATTACH PLAN OF OPERATION OR OTHER APPLICATION]

If the attached [plan of operation or other application] is approved, our company agrees to implement, to the extent prudent and feasible, measures that avoid or minimize harm to historic properties.

____ ________________
Signature Date

____
Name

____
Title

Exhibit 5

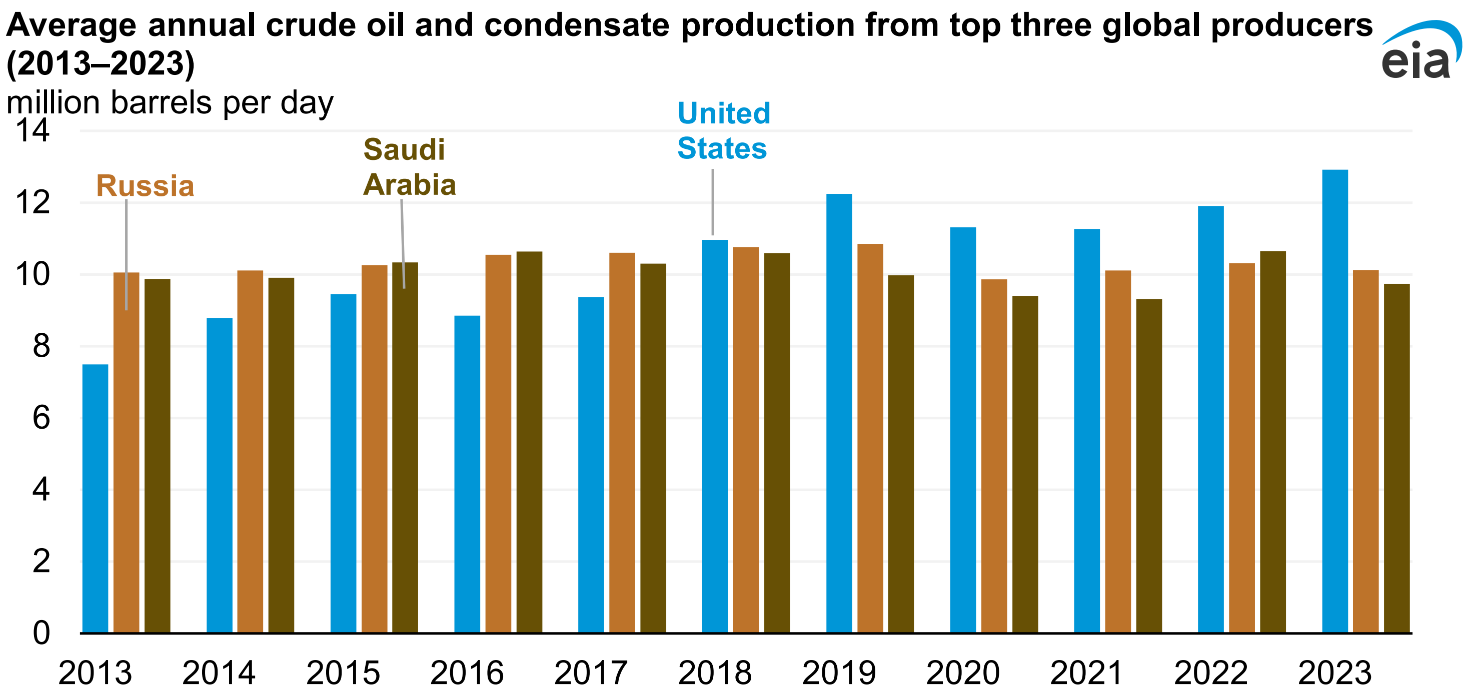
U.S. Energy Information Administration

Today in Energy

IN-BRIEF ANALYSIS

March 11, 2024

United States produces more crude oil than any country, ever



Data source: U.S. Energy Information Administration, International Energy Statistics

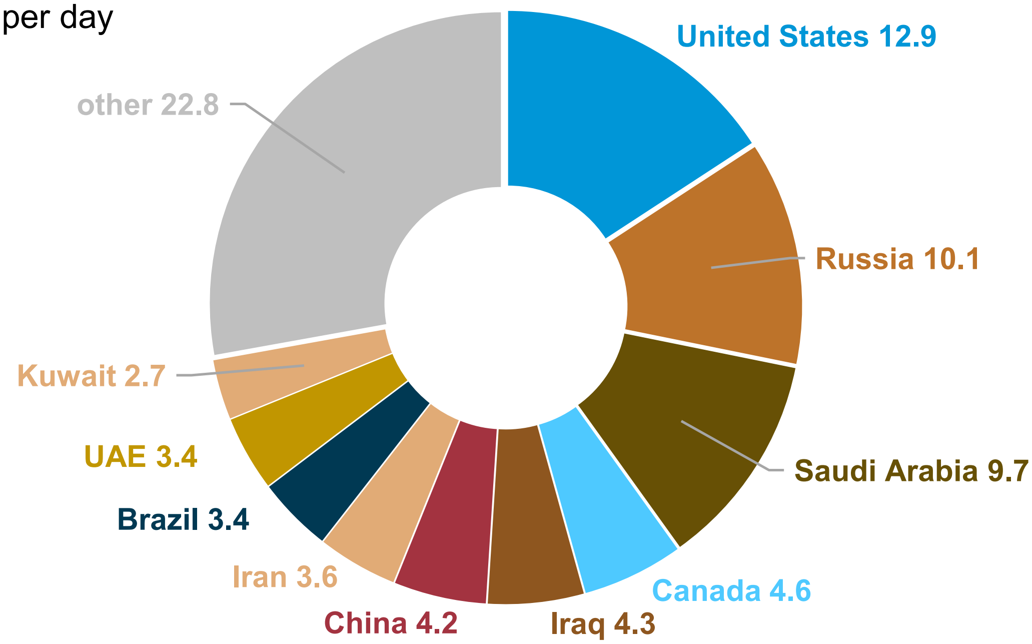
The United States produced more crude oil than any nation at any time, according to our International Energy Statistics, for the past six years in a row. Crude oil production in the United States, including condensate, averaged 12.9 million barrels per day (b/d) in 2023, breaking the previous U.S. and global record of 12.3 million b/d, set in 2019. Average monthly U.S. crude oil production established a monthly record high in December 2023 at more than 13.3 million b/d.

The crude oil production record in the United States in 2023 is unlikely to be broken in any other country in the near term because no other country has reached production capacity of 13.0 million b/d. Saudi Arabia's state-owned Saudi Aramco recently scrapped plans to increase production capacity to 13.0 million b/d by 2027.

Together, the United States, Russia, and Saudi Arabia accounted for 40% (32.8 million b/d) of global oil production in 2023. These three countries have produced more oil than any others since 1971 (counting production in the Russian Federation of the Soviet Union prior to 1991), although the top spot has shifted among them over the past five decades. By comparison, the next three largest producing countries—Canada, Iraq, and China—combined produced 13.1 million b/d in 2023, only slightly more than what was produced in the United States alone.

Global crude oil and condensate production in 2023 by select countries

million barrels per day



Data source: U.S. Energy Information Administration, International Energy Statistics

After peaking at 9.6 million b/d in 1970, annual U.S. crude oil production flattened and then generally declined for decades to a low of 5.0 million b/d in 2008. Crude oil production in the United States began increasing again in 2009, as producers increasingly applied hydraulic fracturing and horizontal drilling techniques, and has increased steadily since. The only exception to U.S. production growth since 2009 was in 2020 and 2021, when demand and prices decreased because of the economic effects of the COVID-19 pandemic. In recent years, crude oil production in the Permian Basin (in western Texas and eastern New Mexico) drove the increases in total crude oil and natural gas production in the United States.

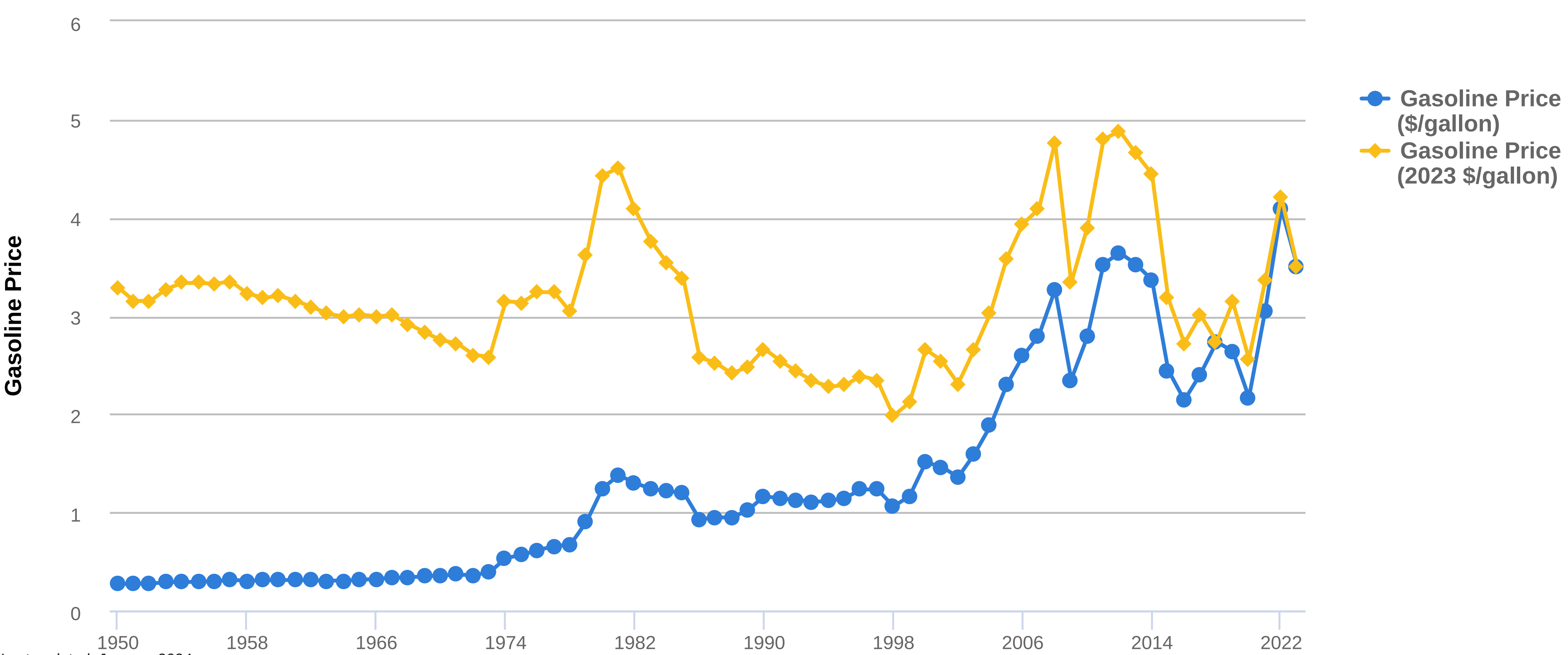
Russia was the country with the most crude oil production in 2017, but production growth in Russia has since lagged behind the United States. Average annual production in Russia peaked in 2019 at 10.8 million b/d, when it trailed the United States by 1.4 million b/d. More recently, Russia was among the OPEC+ countries that announced production cuts in November 2022, and in February 2023, it separately announced additional voluntary cuts of 500,000 b/d. Although voluntary cuts have reduced recent production in Russia, we believe sanctions and voluntary actions by companies in response to the full-scale invasion of Ukraine have been the primary cause of the cuts. Actual cuts to production appear to be smaller than anticipated, however, and we estimate that production in Russia declined by only 200,000 b/d in 2023.

Average annual production in Saudi Arabia peaked in 2022 at 10.6 million b/d, which was 1.3 million b/d less than in the United States that year. In 2023, crude oil production in Saudi Arabia declined by about 900,000 b/d because of OPEC+ cuts and further voluntary cuts Saudi Arabia made to offset weaker demand growth. Production in Saudi Arabia could not exceed the 2023 production volume in the United States because state-owned Saudi Aramco’s stated production capacity is 12.0 million b/d, with about 300,000 b/d of additional capacity from its share of the Neutral Zone area shared with Kuwait.

Principal contributor: Erik Kreil

Exhibit 6

Average Annual Retail Fuel Price of Gasoline



Last updated: January 2024

Printed on: May 21

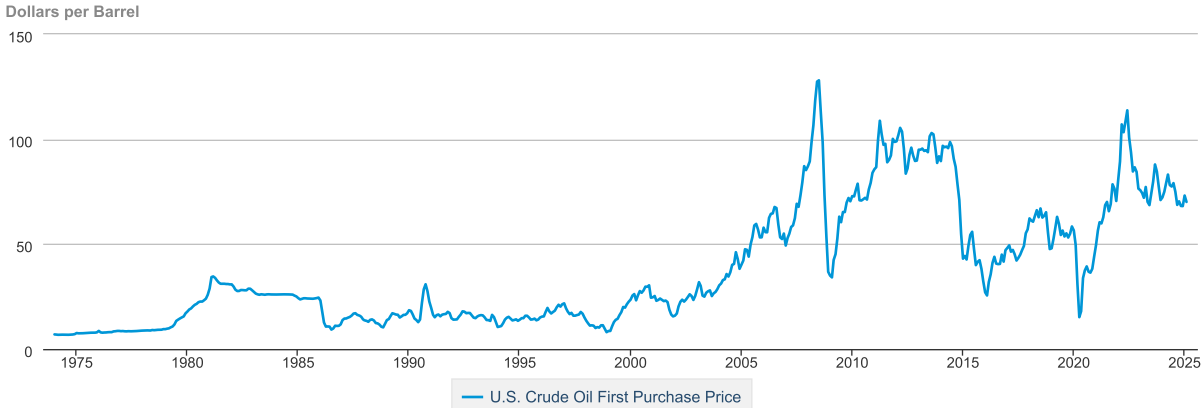
Exhibit 7

Petroleum & Other Liquids

View History: Monthly Annual | Download Data (XLS File)

U.S. Crude Oil First Purchase Price

DOWNLOAD



Data source: U.S. Energy Information Administration

Chart Tools
no analysis applied

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

U.S. Crude Oil First Purchase Price (Dollars per Barrel)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1974	6.95	6.87	6.77	6.77	6.87	6.85	6.80	6.71	6.70	6.97	6.97	7.09
1975	7.61	7.47	7.57	7.55	7.52	7.49	7.75	7.73	7.75	7.83	7.80	7.93
1976	8.63	7.91	7.78	7.86	7.89	8.00	8.04	8.03	8.39	8.46	8.61	8.62
1977	8.50	8.56	8.45	8.41	8.49	8.44	8.47	8.45	8.43	8.72	8.69	8.81
1978	8.71	8.86	8.80	8.82	8.81	9.05	8.96	9.05	9.15	9.17	9.20	9.47
1979	9.46	9.69	9.83	10.33	10.71	11.70	13.39	14.00	14.57	15.06	15.52	17.00
1980	17.86	18.86	19.33	20.28	21.05	21.52	22.31	22.62	22.59	23.23	23.99	25.83
1981	28.81	34.30	34.59	33.92	32.73	31.68	31.10	31.10	31.10	30.98	30.97	30.80
1982	30.80	29.73	28.31	27.64	27.66	28.12	28.09	27.99	27.99	28.76	28.74	28.02
1983	27.22	26.41	26.08	25.85	26.08	25.98	25.86	26.03	26.08	26.04	26.09	25.88
1984	25.93	26.06	26.05	25.93	26.00	26.09	26.11	26.02	25.97	25.92	25.44	25.05
1985	24.26	23.64	23.89	24.19	24.18	24.07	24.04	23.99	23.96	24.10	24.27	24.51
1986	23.12	17.65	12.62	10.68	10.75	10.68	9.25	9.77	11.09	11.00	11.05	11.73
1987	13.79	14.51	14.54	14.95	15.29	15.95	16.88	17.06	16.25	15.95	15.46	14.27
1988	13.64	13.43	12.96	13.92	14.12	13.59	12.38	12.22	11.63	10.62	10.31	11.99
1989	13.80	14.24	15.65	17.04	16.76	16.42	16.32	15.01	15.58	16.25	16.30	17.01
1990	18.49	18.16	16.57	14.52	13.82	12.79	14.03	21.87	28.46	30.86	27.53	22.63
1991	19.60	16.28	15.13	16.16	16.44	15.58	16.36	16.60	16.71	17.72	17.12	14.68
1992	13.99	14.04	14.12	15.36	16.38	17.96	17.80	17.07	17.20	17.16	16.00	14.94
1993	14.70	15.53	15.94	16.15	16.03	15.06	13.83	13.75	13.39	16.27	15.21	12.95

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	10.49	10.71	10.94	12.31	14.02	14.93	15.34	14.50	13.62	13.84	14.14	13.43
1995	14.00	14.71	14.68	15.84	15.85	15.02	14.01	14.13	14.49	13.68	14.03	15.02
1996	15.43	15.54	17.63	19.58	17.94	16.94	17.63	18.29	19.93	21.09	20.20	21.34
1997	21.76	19.38	17.83	16.63	17.23	15.88	15.89	16.19	16.41	17.66	16.83	15.04
1998	13.45	12.17	11.15	11.28	11.13	10.00	10.44	10.20	11.29	11.32	9.64	8.03
1999	8.57	8.60	10.76	12.82	13.92	14.39	16.12	17.58	20.03	19.71	21.35	22.55
2000	23.53	25.48	26.19	23.20	25.58	27.62	26.81	27.91	29.72	29.65	30.36	24.46
2001	24.64	25.27	22.98	23.39	24.06	23.43	22.82	23.08	22.37	18.73	16.40	15.54
2002	15.89	16.93	20.28	22.52	23.51	22.59	23.51	24.76	26.08	25.29	23.38	25.29
2003	28.42	31.85	30.10	25.45	24.95	26.84	27.52	27.94	25.23	26.53	27.21	28.53
2004	30.35	31.21	32.86	33.20	35.73	34.53	36.54	40.10	40.56	46.14	42.85	38.22
2005	40.18	42.19	47.56	47.26	44.03	49.83	53.35	58.90	59.64	56.99	53.20	53.24
2006	57.85	55.69	55.64	62.52	64.40	64.65	67.71	67.21	59.37	53.26	52.42	55.03
2007	49.32	52.94	54.95	58.20	58.90	62.35	69.23	67.77	73.27	79.32	87.16	85.28
2008	87.06	89.41	98.44	106.64	118.55	127.47	128.08	112.83	98.50	73.18	53.67	36.80
2009	35.00	34.14	42.45	45.19	52.67	63.09	60.44	65.28	65.28	69.82	71.99	70.42
2010	72.87	72.74	75.77	78.80	70.91	70.77	71.37	72.07	71.23	76.02	79.20	83.98
2011	85.66	86.69	99.19	108.80	102.46	97.30	97.82	89.00	90.22	92.28	100.18	98.71
2012	98.99	102.04	105.42	103.62	95.57	83.59	86.10	92.53	95.98	92.24	89.64	89.81
2013	95.00	95.01	95.54	94.41	94.75	93.82	101.41	102.96	102.32	96.18	88.70	91.85
2014	89.57	96.86	96.17	96.49	95.74	98.68	96.70	90.72	86.87	78.84	71.07	54.86
2015	43.06	44.35	42.66	49.30	54.38	55.88	47.70	39.98	41.60	42.34	38.19	32.26
2016	27.02	25.52	31.87	35.59	41.02	43.96	40.71	40.46	40.55	45.00	41.65	47.12
2017	48.19	49.41	46.39	47.23	45.19	42.17	43.42	44.96	47.17	49.12	55.19	56.98
2018	62.25	61.18	60.68	63.50	66.16	62.80	67.00	62.64	63.54	65.18	55.65	47.63
2019	48.00	52.60	57.46	63.00	59.73	54.34	56.47	53.63	55.14	53.14	54.96	58.41
2020	56.55	49.66	31.01	15.18	18.02	33.81	37.44	39.37	36.82	36.39	38.25	43.92
2021	49.47	56.44	60.43	59.87	62.80	68.58	70.12	65.68	69.09	78.51	76.45	70.56
2022	80.33	89.41	107.07	103.34	108.29	113.77	100.84	93.76	84.62	86.61	84.43	76.45
2023	75.71	74.32	72.09	77.23	70.14	68.59	74.07	79.78	87.96	84.65	77.46	71.01
2024	72.26	74.96	78.97	83.15	78.16	77.45	79.07	74.97	68.70	70.39	68.19	68.12
2025	73.15	70.11										

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 5/1/2025
Next Release Date: 6/2/2025

Exhibit 8

Natural Gas

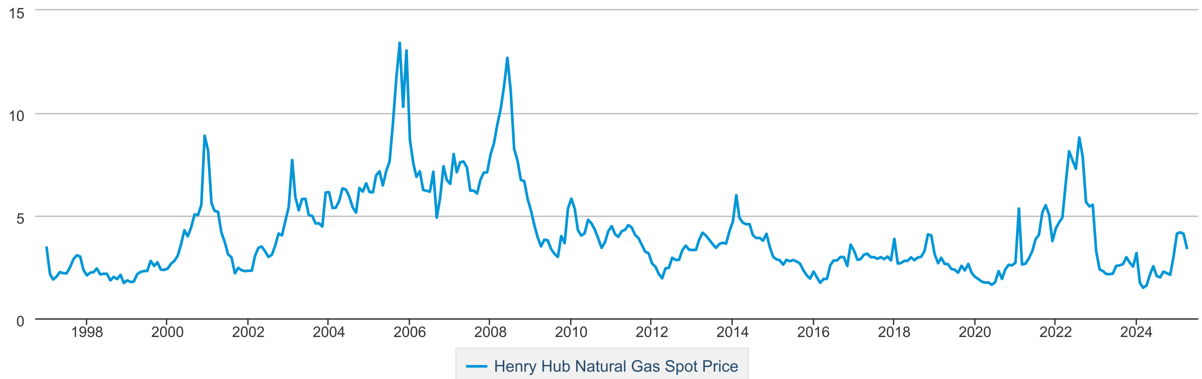
OVERVIEW | DATA | ANALYSIS & PROJECTIONS | GLOSSARY | FAQS

View History: Daily Weekly Monthly Annual | Download Data (XLS File)

Henry Hub Natural Gas Spot Price

DOWNLOAD

Dollars per Million Btu



THOMSON REUTERS

Chart Tools

no analysis applied

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	3.45	2.15	1.89	2.03	2.25	2.20	2.19	2.49	2.88	3.07	3.01	2.35
1998	2.09	2.23	2.24	2.43	2.14	2.17	2.17	1.85	2.02	1.91	2.12	1.72
1999	1.85	1.77	1.79	2.15	2.26	2.30	2.31	2.80	2.55	2.73	2.37	2.36
2000	2.42	2.66	2.79	3.04	3.59	4.29	3.99	4.43	5.06	5.02	5.52	8.90
2001	8.17	5.61	5.23	5.19	4.19	3.72	3.11	2.97	2.19	2.46	2.34	2.30
2002	2.32	2.32	3.03	3.43	3.50	3.26	2.99	3.09	3.55	4.13	4.04	4.74
2003	5.43	7.71	5.93	5.26	5.81	5.82	5.03	4.99	4.62	4.63	4.47	6.13
2004	6.14	5.37	5.39	5.71	6.33	6.27	5.93	5.41	5.15	6.35	6.17	6.58
2005	6.15	6.14	6.96	7.16	6.47	7.18	7.63	9.53	11.75	13.42	10.30	13.05
2006	8.69	7.54	6.89	7.16	6.25	6.21	6.17	7.14	4.90	5.85	7.41	6.73
2007	6.55	8.00	7.11	7.60	7.64	7.35	6.22	6.22	6.08	6.74	7.10	7.11
2008	7.99	8.54	9.41	10.18	11.27	12.69	11.09	8.26	7.67	6.74	6.68	5.82
2009	5.24	4.52	3.96	3.50	3.83	3.80	3.38	3.14	2.99	4.01	3.66	5.35
2010	5.83	5.32	4.29	4.03	4.14	4.80	4.63	4.32	3.89	3.43	3.71	4.25
2011	4.49	4.09	3.97	4.24	4.31	4.54	4.42	4.06	3.90	3.57	3.24	3.17
2012	2.67	2.51	2.17	1.95	2.43	2.46	2.95	2.84	2.85	3.32	3.54	3.34
2013	3.33	3.33	3.81	4.17	4.04	3.83	3.62	3.43	3.62	3.68	3.64	4.24
2014	4.71	6.00	4.90	4.66	4.58	4.59	4.05	3.91	3.92	3.78	4.12	3.48
2015	2.99	2.87	2.83	2.61	2.85	2.78	2.84	2.77	2.66	2.34	2.09	1.93
2016	2.28	1.99	1.73	1.92	1.92	2.59	2.82	2.82	2.99	2.98	2.55	3.59

2017	3.30	2.85	2.88	3.10	3.15	2.98	2.98	2.90	2.98	2.88	3.01	2.82
2018	3.87	2.67	2.69	2.80	2.80	2.97	2.83	2.96	3.00	3.28	4.09	4.04
2019	3.11	2.69	2.95	2.65	2.64	2.40	2.37	2.22	2.56	2.33	2.65	2.22
2020	2.02	1.91	1.79	1.74	1.75	1.63	1.76	2.30	1.92	2.39	2.61	2.58
2021	2.71	5.35	2.62	2.66	2.91	3.26	3.84	4.07	5.16	5.51	5.05	3.76
2022	4.38	4.69	4.90	6.60	8.14	7.70	7.28	8.81	7.88	5.66	5.45	5.53
2023	3.27	2.38	2.31	2.16	2.15	2.18	2.55	2.58	2.64	2.98	2.71	2.52
2024	3.18	1.72	1.49	1.60	2.12	2.54	2.07	1.99	2.28	2.20	2.12	3.01
2025	4.13	4.19	4.12	3.42								

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 5/21/2025
Next Release Date: 5/29/2025

Exhibit 9

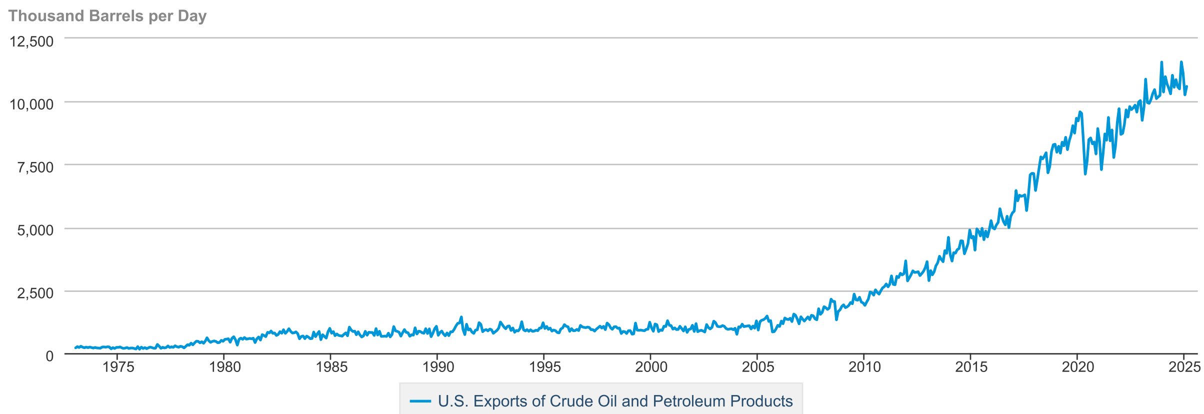
Petroleum & Other Liquids

OVERVIEW | DATA | ANALYSIS & PROJECTIONS

View History: Monthly Annual | Download Data (XLS File)

U.S. Exports of Crude Oil and Petroleum Products

DOWNLOAD



Data source: U.S. Energy Information Administration

Chart Tools
no analysis applied

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

U.S. Exports of Crude Oil and Petroleum Products (Thousand Barrels per Day)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1973	211	261	224	276	237	215	241	218	243	222	203	228
1974	207	203	196	243	247	238	253	247	171	221	186	231
1975	228	248	213	190	202	224	186	203	205	187	166	262
1976	156	241	185	222	179	213	242	220	196	198	348	279
1977	192	234	207	223	288	225	254	230	294	255	235	274
1978	257	208	269	337	313	399	330	411	477	469	409	455
1979	392	486	611	493	429	468	486	466	414	425	510	471
1980	550	558	573	434	591	654	531	319	557	598	549	622
1981	558	569	586	570	595	420	571	644	519	738	701	656
1982	829	804	882	786	803	703	741	858	791	932	786	860
1983	973	865	801	809	848	774	571	663	684	576	679	639
1984	575	582	840	655	766	864	536	732	664	599	854	986
1985	792	857	694	764	705	692	675	749	806	690	1,036	925
1986	859	876	732	850	724	642	685	868	714	831	821	820
1987	703	977	720	870	666	669	680	664	795	646	737	1,057
1988	885	864	834	676	814	938	826	814	673	732	717	1,008
1989	761	875	860	810	791	975	780	967	655	791	975	1,067
1990	709	822	880	761	690	803	696	850	847	949	1,085	1,187
1991	1,199	1,441	944	737	1,149	921	963	837	785	918	926	1,213
1992	1,144	852	912	937	885	957	929	789	848	902	995	1,237
1993	1,135	1,033	970	1,067	1,082	900	1,001	829	902	881	980	1,250

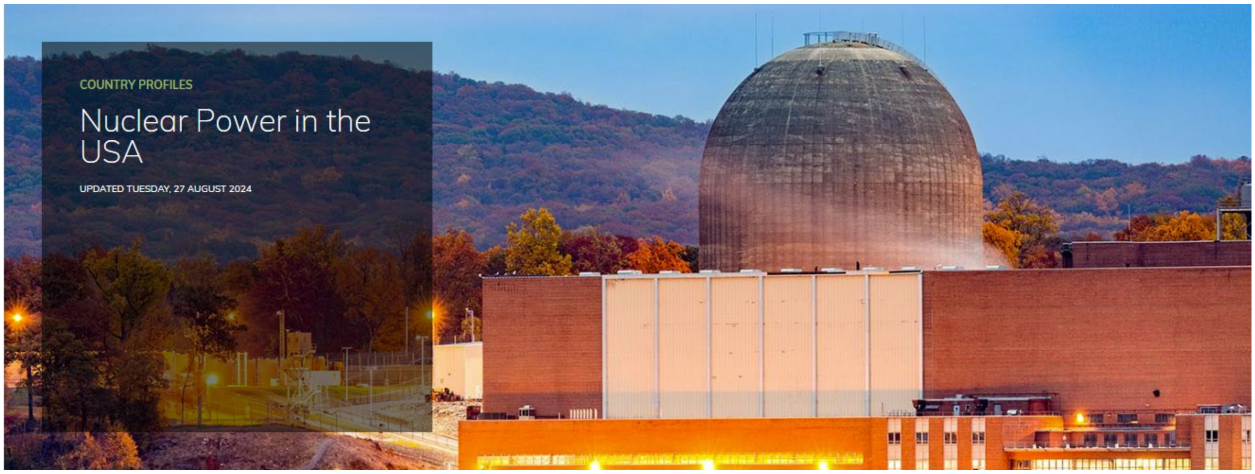
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	927	882	936	868	929	867	877	913	891	997	1,000	1,208
1995	978	1,062	948	998	876	919	895	821	805	962	1,002	1,135
1996	1,070	1,048	867	976	891	895	945	896	1,104	1,045	1,024	1,013
1997	1,038	1,017	933	937	876	955	1,012	1,074	997	1,066	934	1,197
1998	1,133	1,003	948	1,048	1,053	987	998	780	863	851	782	893
1999	896	756	764	1,196	915	907	918	902	889	944	950	1,230
2000	1,006	870	1,159	1,131	856	925	900	1,073	1,059	1,292	1,108	1,095
2001	954	1,004	938	942	1,069	976	879	1,048	825	946	960	1,109
2002	861	1,175	853	890	910	880	839	1,138	1,015	962	1,026	1,272
2003	1,212	1,067	1,051	1,053	1,097	1,065	976	947	960	970	933	990
2004	748	1,046	1,024	1,153	1,052	1,070	1,080	1,091	961	1,078	992	1,284
2005	917	1,256	1,308	1,330	1,380	1,477	1,259	1,295	844	854	961	1,106
2006	1,059	1,276	1,170	1,398	1,350	1,334	1,387	1,255	1,554	1,506	1,353	1,164
2007	1,446	1,350	1,274	1,360	1,441	1,331	1,506	1,483	1,361	1,325	1,767	1,542
2008	1,620	1,848	1,807	1,739	1,793	2,146	2,051	2,053	1,323	1,658	1,720	1,856
2009	1,922	1,808	1,838	1,900	2,015	1,963	2,348	2,119	2,105	2,223	2,029	1,996
2010	1,897	2,034	2,149	2,432	2,399	2,304	2,516	2,410	2,345	2,480	2,598	2,644
2011	2,750	2,634	2,733	3,071	2,735	2,716	3,053	3,002	3,174	3,107	3,159	3,667
2012	2,870	2,994	3,116	3,272	3,207	3,216	3,237	3,081	3,164	3,255	3,404	3,636
2013	2,881	3,280	3,111	3,235	3,472	3,594	3,851	3,725	3,632	4,074	3,967	4,602
2014	3,911	3,658	3,993	3,974	4,113	4,155	4,464	4,457	3,947	4,134	4,353	4,892
2015	4,575	4,640	4,092	4,938	4,853	4,657	4,960	4,507	4,851	4,617	4,903	5,266
2016	4,977	4,934	5,092	5,195	5,739	5,437	5,226	5,097	5,439	4,985	5,426	5,574
2017	5,645	6,461	6,054	6,277	6,232	6,252	6,291	5,665	6,289	7,086	7,144	7,136
2018	6,461	6,907	7,337	7,797	7,717	7,824	7,963	7,164	7,415	8,011	8,281	8,301
2019	7,982	8,219	7,946	8,382	8,238	8,576	8,084	8,438	8,672	9,039	8,741	9,331
2020	9,228	9,589	9,522	8,353	7,112	7,608	8,485	8,550	8,315	8,389	7,913	8,924
2021	8,419	7,291	7,896	8,709	8,460	9,365	8,434	8,867	7,772	8,226	9,185	9,714
2022	8,690	8,735	9,070	9,665	9,379	9,798	9,675	9,747	9,854	9,575	9,979	10,035
2023	9,248	9,777	10,885	9,951	9,924	10,084	10,319	10,471	10,112	10,180	10,237	11,565
2024	10,372	10,985	10,701	10,514	10,302	11,041	10,562	10,866	10,575	10,497	11,572	11,131
2025	10,260	10,598										

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 4/30/2025
Next Release Date: 5/30/2025

Exhibit 10

WORLD NUCLEAR ASSOCIATION



- The USA is the world's largest producer of nuclear power, accounting for about 30% of worldwide generation of nuclear electricity.
- The country's nuclear reactors produced 772 TWh in 2022, 18% of total electrical output.
- Vogtle 3 was connected to the grid in April 2023, followed by unit 4 in March 2024.
- The Inflation Reduction Act was signed into law in August 2022. The Act provides support for existing and new nuclear development through investment and tax incentives for both large existing nuclear plants and newer advanced reactors, as well as high-assay low enriched uranium (HALEU) and hydrogen production.
- Some states have liberalized wholesale electricity markets, which makes the financing of capital-intensive power projects difficult, and coupled with lower gas prices since 2009, have put the economic viability of some existing reactors and proposed projects in doubt.

- 94
- Operable Reactors
- **96,952 MWe**

0

Reactors Under Construction

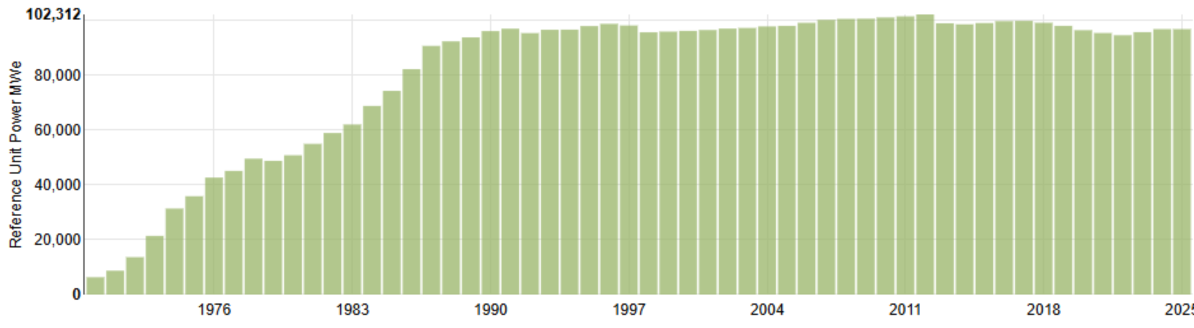
0 MWe

41

Reactors Shutdown

20,017 MWe

Operable nuclear power capacity



Electricity sector

Total generation (in 2022): 4502 TWh

Generation mix: natural gas 1742 TWh (39%); coal 909 TWh (20%); nuclear 804 TWh (18%); wind 440 TWh (10%); hydro 286 TWh (6%); solar 189 TWh (4%); biofuels & waste 66.8 TWh; oil 41.5 TWh; geothermal 19.6 TWh.

Import/export balance: 41.2 TWh net import (56.9 TWh imports; 15.7 TWh exports)

Total consumption: 4071 TWh

Per capita consumption: c. 12,000 kWh in 2022

Source: International Energy Agency and The World Bank. Data for year 2022.

In its Annual Energy Outlook 2022, the US Energy Information Administration's (EIA's) reference case shows electricity demand growth averaging 1% per year through to 2050.

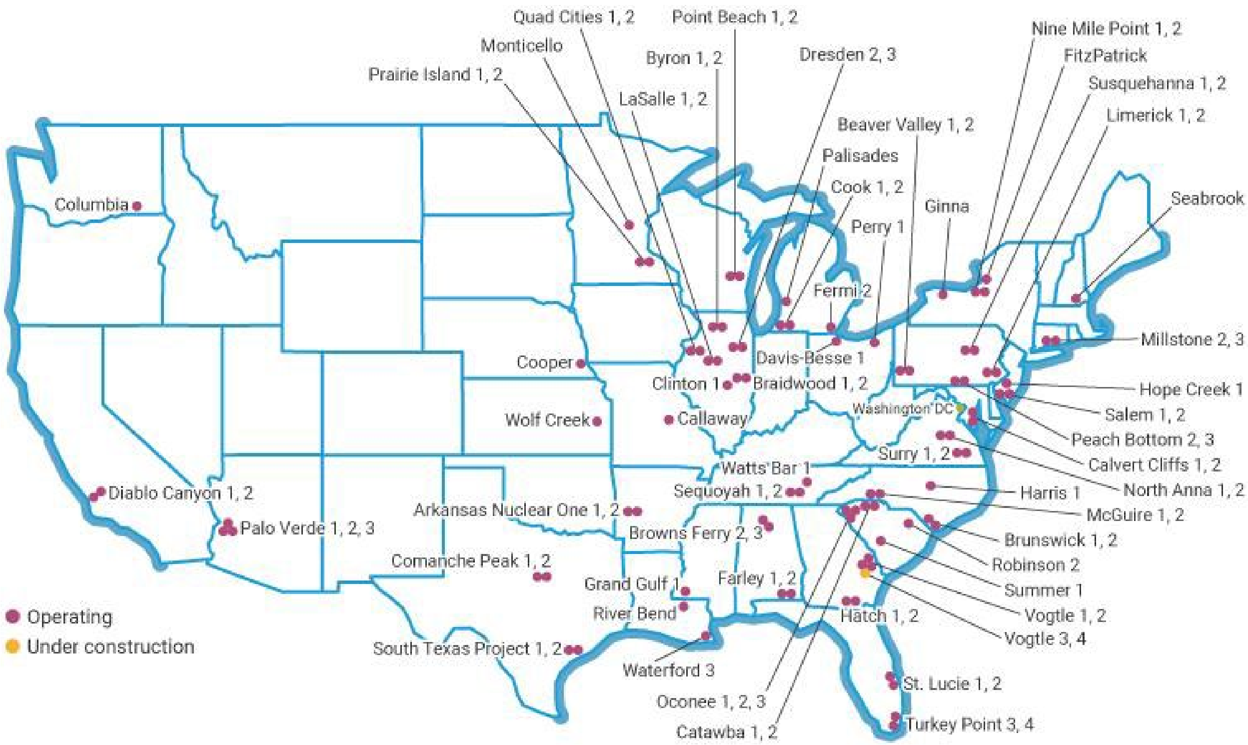
Nuclear power plays a major role in electricity provision across the country. The US fleet is operated by 30 different power companies across 30 different states. Since 2001 these plants have achieved an average capacity factor of over 90%. The average capacity factor has risen from 50% in the early 1970s, to 70% in 1991, and it passed 90% in 2002, remaining at around this level since. In 2019 it was a record 94%, compared with wind (32%) and solar PV (22%) (EIA data). The industry invests about $7.5 billion per year in maintenance and upgrades of the plants.

Given that nuclear plants generate nearly 20% of the nation’s electricity overall and about 55% of its carbon-free electricity, even a modest increase in electricity demand would require significant new nuclear capacity in order to maintain this share. If today’s nuclear plants retire after 60 years of operation, 22 GWe of new nuclear capacity would be needed by 2030, and 55 GWe by 2035 to maintain a 20% nuclear share.

Since about 2010 the prospect of sustained low natural gas prices has dampened plans for new nuclear capacity (see section on New nuclear capacity below).

Nuclear power industry

Reactors operating in the United States



A table of operable plants in the USA is available as an appendix to this page.

Almost all the US nuclear generating capacity comes from reactors built between 1967 and 1990. Until 2013 there had been no new construction starts since 1977, largely because for a number of years gas generation was considered more economically attractive and because construction schedules during the 1970s and 1980s had frequently been extended by opposition, and compounded by heightened safety fears following the Three Mile Island accident in 1979. A further PWR – Watts Bar 2 – started up in 2016 following Tennessee Valley Authority's (TVA's) decision in 2007 to complete the construction of the unit.

Despite a near halt in new construction for more than 30 years, US reliance on nuclear power has grown. In 1980, nuclear plants produced 251 TWh, accounting for 11% of the country's electricity generation. In 2019, that output had risen to 809 TWh and nearly 20% of electricity, providing more than 30% of the electricity generated from nuclear power worldwide. Much of the increase came from the 47 reactors, all approved for construction before 1977, that came online in the late 1970s and 1980s, more than doubling US nuclear generation capacity. The US nuclear industry has also achieved remarkable gains in power plant utilisation through improved refuelling, maintenance and safety systems at existing plants. Average nuclear generation costs have come down from $51.22/MWh in 2012 to $30.92/MWh in 2022. This 40% reduction in nuclear generating costs since 2012 has been driven by: a 41% decrease in fuel costs; a 51% decrease in capital expenditures; and a 33% decrease in operating costs.[9]

Reactor lifetime extensions and regulation

The Nuclear Regulatory Commission (NRC) is the government agency established in 1974 to be responsible for regulation of the nuclear industry, notably reactors, fuel cycle facilities, materials and waste (as well as other civil uses of nuclear material).

In an historic move, the NRC in March 2000 renewed the operating licences of the two-unit Calvert Cliffs nuclear power plant for an additional 20 years. In March 2019 the NRC renewed the licence for Seabrook, extending the unit’s operation by 20 years to 2050. This took the number of US power reactors that have renewed their licences to 94, several of which have since shut down. Hence, almost all of the US power reactors are likely to be licensed to operate for 60 years, with owners undertaking major capital works to upgrade them at around 30-40 years. The licence renewal process typically costs $16-25 million, and the procedures for such renewals, with public meetings and thorough safety review, are exhaustive.

The original 40-year licences were always intended to be renewed in 20-year increments, as the 40-year period was more to do with amortisation of capital rather than implying that reactors were designed for only that operational lifespan. It was also a conservative measure, and experience since has identified life-limiting factors and addressed them. The NRC is now considering applications for the extension of operating licences beyond 60 out to 80 years, with its subsequent licence renewal (SLR) programme. As of March 2024:

- Reactors approved (to 80 years): Turkey Point 3&4, Peach Bottom 2&3, Surry 1&2.
- Reactors under review: North Anna 1&2, Point Beach 1&2, Oconee 1-3, St. Lucie 1&2, Monticello, Virgil C. Summer 1, Browns Ferry 1-3.
- Reactors expected to apply: H.B. Robinson 2, Dresden 2&3, Edwin I. Hatch 1&2, Prairie Island 1&2, Donald C. Cook 1&2.

In October 2020 Duke Energy said it intended to seek second 20-year renewals for all 11 of its reactors.

The licence extensions to 60 years and beyond meant that major mid-life refurbishment, such as replacement of steam generators and upgrades of instrument and control systems, could be justified. While active plant components such as pumps and valves are under continuous scrutiny for operability, passive components need to be assessed for ageing which may have weakened them. There are R&D programmes focusing on this run by the Department of Energy (DOE), Electric Power Research Institute (EPRI), and American Society of Mechanical Engineers (ASME).

The NRC's reactor oversight and assessment process yields publicly-accessible information on the performance of plants in 19 key areas (14 indicators on plant safety, two on radiation safety and three on security). Performance against each indicator is reported quarterly on the NRC website according to whether it is normal, attracting regulatory oversight, provoking regulatory action, or unacceptable (in which case the plant would probably be shut down).

On the industry side, the Institute of Nuclear Power Operations (INPO) was formed after the Three Mile Island accident in 1979, to establish standards of performance against which individual plants could be regularly measured. An inspection of each member plant is typically performed every 18 to 24 months.

Following the accident at Japan's Fukushima nuclear plant in March 2011, which was exacerbated by inadequate outside assistance to the flooded reactors, the US nuclear industry set up the 'FLEX' accident response strategy. It has 61 centres across the country and two national centres which together provide the capacity to respond to nuclear power plant accidents anywhere in the country within 24 hours.

In January 2023 Xcel Energy applied to the US Nuclear Regulatory Commission for a second 20-year operating licence renewal for the Monticello nuclear power plant.

In February 2023 Constellation Energy announced plans to invest $800 million in new equipment to increase the output of its Braidwood and Byron nuclear power plants in Illinois by approximately 135 MWe.

Nuclear industry development

The USA was a pioneer of nuclear power development.[a] Westinghouse designed the first fully commercial pressurised water reactor (PWR), a unit of 250 MWe capacity, Yankee Rowe, which started up in 1960 and operated to 1992. Meanwhile the boiling water reactor (BWR) was developed by the Argonne National Laboratory, and the first commercial plant, Dresden 1 (250 MWe) designed by General Electric, was started up in 1960. A prototype BWR, Vallecitos, ran from 1957 to 1963.

By the end of the 1960s, orders were being placed for PWR and BWR reactor units of more than 1000 MWe capacity, and a major construction program got under way. These remain practically the only types built commercially in the USA.[b]

Nuclear developments in USA suffered a major setback after the 1979 Three Mile Island accident, though that actually validated the very conservative design principles of Western reactors, and no-one was injured or exposed to harmful radiation. Many orders and projects were cancelled or suspended, and the nuclear construction industry went into the doldrums for two decades. Nevertheless, by 1990 over 100 commercial power reactors had been commissioned.

Most of these were built by regulated utilities, often state-based, which meant that they put the capital cost (whatever it turned out to be after, for example, delays) into their rate base and amortised it against power sales. Their consumers bore the risk and paid the capital cost. (With electricity deregulation in some states, the shareholders bear any risk of capital overruns and power is sold into competitive markets.)

Operationally, from the 1970s the US nuclear industry dramatically improved its safety and operational performance, and by the turn of the century it was among world leaders, with average net capacity factor over 90%.

This performance was achieved as the US industry continued deregulation, begun with passage of the Energy Policy Act in 1992. Changes accelerated after 1998, including mergers and acquisitions affecting the ownership and management of nuclear power plants.

In August 2022 the Inflation Reduction Act was passed by the US House of Representatives and later that month signed into law by President Joe Biden. The energy provisions in the Act outline support for existing and new nuclear development through investment and tax incentives for both large existing nuclear plants and newer advanced reactors, as well as HALEU and hydrogen production.

New nuclear capacity

From 1992 to 2005, some 270,000 MWe of new gas-fired plant was built, and only 14,000 MWe of new nuclear and coal-fired capacity came online. But coal and nuclear supplied almost 70% of US electricity at the time and provided price stability. When investment in these two technologies almost disappeared, unsustainable demands were placed on gas supplies and prices quadrupled, forcing large industrial users of it offshore and pushing gas-fired electricity costs towards 10 ¢/kWh. Today, due to the advent of shale gas, costs are much lower.

The reason for investment being predominantly in gas-fired plant was that it offered the lowest investment risk. Several uncertainties inhibited investment in capital-intensive new coal and nuclear technologies. About half of US generating capacity is over 30 years old, and major investment is also required in transmission infrastructure. This creates an energy investment crisis which was recognised in Washington, along with an increasing bipartisan consensus on the strategic importance and clean air benefits of nuclear power in the energy mix.

The Energy Policy Act 2005 then provided a much-needed stimulus for investment in electricity infrastructure including nuclear power. New reactor construction got under way from 2012, with two units at the Vogtle nuclear power plant, and two units at the Summer nuclear power plant.*

* The project at Summer was subsequently cancelled.

Continued low gas prices depress the prospects for commitment to further construction, and it is generally considered that natural gas prices need to recover to $8/GJ or /MMBtu before there is renewed confidence in deregulated states. In regulated states, a longer-term outlook is possible. Small modular reactors provide possible relief from major upfront finance burdens, but these are some way off having design certification from the NRC.

There are three regulatory initiatives which in recent years have enhanced the prospects of building new plants. First is the design certification process, second is provision for early site permits (ESPs) and third is the combined construction and operating licence (COL) process ('Part 52') as an alternative to the 'Part 50' two-step process of construction permit followed by operating licence. All have some costs shared by the DOE.

Vogtle 3&4

In April 2008, Georgia Power signed an EPC contract with Westinghouse and The Shaw Group (now CB&I) consortium for two 1200 MWe Westinghouse AP1000 reactors which will be licensed and operated by Southern Nuclear Operating Company (SNOC). Both Georgia Power and SNOC are subsidiaries of Southern Company. JSW in Japan sent forged components to Doosan in South Korea for fabrication. The COL was issued by the NRC in February 2012. Construction start (first concrete) was delayed to late 2012, and then to March 2013, after NRC issued a licence amendment allowing use of a higher-strength concrete that permits the company to pour the foundation of the new reactors without making additional modifications to reinforcing steel bar. At that point ten million working hours had been invested on the site. Shaw (now CB&I) agreed with China's State Nuclear Power Technology Corporation (SNPTC) to deploy engineers with experience in building China's AP1000 units to provide technical support. Following early delays, construction of unit 3 started in March 2013 and unit 4 in November. Fluor joined the project as construction manager in January 2016, taking over part of the CB&I role, and in January 2017 Bechtel became involved with the nuclear islands. The units were initially expected online late in 2019 and September 2020. It is a regulated plant, with guaranteed operational cost recovery.

Reactor pressure vessels and steam generators are from Doosan in South Korea.

Georgia Power as 45.7% owner reduced its earlier cost estimate for building its share of the new plant from \$6.4 billion to \$6.1 billion as a result of being able to recover financing costs from customers during construction, but this increased to \$6.2 billion in 2012 due to delays. Over the life of the plant, the utility's customers will save about $1 billion through federal loan guarantees, production tax credits and the early recovery of financing costs in the rate base. The Georgia Public Service Commission in February 2013 approved Georgia Power's costs for the project and said that the project "remains more economically viable than any other [energy] resource, including a natural gas-fired alternative."

The initial cost estimate for the project was $14 billion. Delays to mid-2014 resulted in a cost increase of $381 million but this was offset by lower interest rates than budgeted. When further delays were announced in January 2015, the company said that cost escalation was about $10 million per month plus financing cost of about $30 million per month. Minority equity in the project is held by Oglethorpe Power (30%), the Municipal Electric Authority of Georgia – MEAG Power (22.7%), and Dalton city (1.6%).

Loan guarantees totalling $3.5 billion were issued to Georgia Power and $3 billion to Oglethorpe Power in 2014. A further $1.8 billion of loan guarantees were issued to three subsidiaries of MEAG Power in June 2015, making a total of $8.3 billion. (Dalton Utilities did not seek a loan guarantee.) In August 2017 Georgia Power, Oglethorpe Power and MEAG sought further loan guarantees to help them complete the project. In September 2017 the DOE announced conditional commitments for further loan guarantees of up to $3.7 billion: $1.67 billion to Georgia Power, $1.6 billion to Oglethorpe Power, and $415 million to three subsidiaries of MEAG Power. (Dalton Utilities again did not apply.) These were granted in March 2019. The DOE said: "Advanced nuclear energy projects like Vogtle are the kind of important energy infrastructure projects that support a reliable and resilient grid, promote economic growth, and strengthen our energy and national security."

Earlier, in mid-April 2017, Westinghouse said that about $1.5 billion was required to complete the construction of both units, though other estimates are higher. In June Toshiba agreed with the owners that its liability under its 2008 parental guarantee would be capped at $3.68 billion for the completion of the Vogtle units. The sum is part of an $8.9 billion provision in Toshiba's accounts announced in mid-May, covering all four US reactors.

In mid-May 2017 Georgia Power announced that from June, Southern Nuclear Operating Company (SNOC) would take over project management to complete the Vogtle units, leaving Westinghouse simply as the vendor, though supporting EPC and licensing as well as providing access to intellectual property. Southern said that productivity at the site had improved significantly in 2017, with the reactors now two-thirds complete. SNOC will also be the operator. The company said it would "take all actions necessary to hold Westinghouse and Toshiba accountable for their financial obligations."

After a review of options and contingencies, at the end of August 2017 Georgia Power, supported by the co-owners, recommended to the state public services commission (PSC) that construction of both units should be completed, this being the most economic choice for customers. The total rate impact of the project remains less than originally estimated, it said. The recommendation was unanimously approved by the PSC in December 2017.

At the same time Georgia Power announced it had contracted with Bechtel to manage daily construction efforts under the direction of SNOC. Bechtel has been involved with the project since January, correlated with "a marked increase in productivity" providing "every indication that we can do a better job than Westinghouse alone as we move forward to complete the project." Vogtle 3&4 would begin commercial operation in November 2021 and November 2022 respectively, under a new construction schedule. These dates were reaffirmed by Southern Company in September 2020, at which point construction of the two units was 87% complete. However, in April 2021 Southern Company said it was targeting a December 2021 in-service date for unit 3, and in May 2021 officials told the Georgia Public Service Commission that the likely commercial start date was January 2022. In-service dates were moved to Q3 2022 and Q2 2023 in October 2021, before being moved again in February 2022, to Q1 2023 and Q4 2023.

In August 2022 the NRC granted authorization to Southern Company to load fuel and begin commissioning activities at Vogtle 3. Southern said it was aiming to carry out fuel loading before the end of October 2022.

In January 2023 Georgia Power notified the US Securities and Exchange Commission that Vogtle 3's initial criticality would be delayed after vibrations in the plant's cooling system were found and an issue with a dripping valve was identified during start-up and pre-operational testing. A month later, Southern Company announced that the vibration issue had been remediated and testing had resumed. However, an unexpected issue with flow rates through reactor coolant pumps delayed the schedule.

Unit 3 was connected to the grid on 1 April 2023, and entered commercial operation in July. Fuel loading at unit 4 began in August 2023. In October 2023 a motor fault was discovered in a reactor coolant pump at unit 4, slightly delaying its commercial operation to March 2024. In February 2024 vibrations in the cooling system similar in nature to those experienced during the construction of unit 3 were observed at unit 4. In March 2024 unit 4 was connected to the grid.

Georgia Power (45.7% owner) said it had invested about $4.3 billion in capital costs in the project to June 2017 and in August 2018 announced that it had revised its forecast for the cost of its 45% share of the project up to $8.4 billion. The total price for the project in November 2021 was estimated to be over $28 billion. In May 2022 this increased to $30.34 billion.

Summer 2&3

In May 2008, South Carolina Electricity & Gas (SCANA subsidiary) and state-owned Santee Cooper signed an EPC contract with Westinghouse and the Shaw Group (now CB&I) consortium for two 1200 MWe Westinghouse AP1000 reactors. The total forecast cost of $9.8 billion included inflation and owners' costs for site preparation, contingencies and project financing, though the last was reduced and the total estimated in April 2012 was $9.2 billion. In October 2014 the cost was estimated at over $11 billion, and in 2015 SCEG amended the EPC contract to choose a fixed price option for completion of the units. In November 2016 the state public service commission agreed for SCEG's 55% share to be $7.66 billion, excluding financing, with the company's return on equity reduced to 10.25%. "These delays and related cost increases are principally due to design and fabrication issues associated with the production of submodules used in construction of the units," according to SCANA. Fluor joined the project as construction manager in January 2016, taking over the CB&I role. In February 2017 the anticipated completion dates for the two units were April 2020 and December 2020.

The COL was issued by the NRC at the end of March 2012, and construction of unit 2 commenced in March 2013, with first main concrete. That for unit 3 was in November 2013. (In September 2011 SCEG had started to assemble the containment vessel for the first unit – 43 mm thick, from Chicago Bridge & Iron – and was starting construction on the four low-profile forced-draft cooling towers.) Reactor pressure vessels and steam generators are from Doosan in South Korea. A crane capable of lifting 6800 tonnes is installed onsite, though the heaviest component was 1550 tonnes. SCEG's loan guarantee application was accepted by the DOE and the project was short-listed in May 2009, though nothing has happened since then. It is a regulated plant, with guaranteed operational cost recovery.

In 2014 it was announced that SCEG's stake in the project would be increased to 60% by acquisition of 5% from Santee Cooper after the plant starts up, for about $500 million, leaving it with 40%. Duke Energy

Carolinas had been seeking up to 10% of the project from Santee Cooper, but this plan was dropped in January 2014.

Following Westinghouse filing for Chapter 11 protection from creditors in March 2017, SCANA reviewed the project and initially expected resources from Westinghouse and Toshiba – including a so-called parental guarantee from Toshiba – to be adequate to compensate for the additional costs. These, together with a surety bond and an escrow of AP1000 intellectual property and software, were considered. SCANA and Santee Cooper had intended to take over project management to complete the Summer units, leaving Westinghouse simply as vendor, though supporting EPC and licensing as well as providing access to intellectual property, as with Vogtle. In mid-April Westinghouse told SCANA that about $1.5 billion was required to complete construction of both units – $829 million more than it was entitled to charge under the EPC contract, but less than the liability amount for it and Toshiba for breach of EPC contract. SCE&G and Santee Cooper reached agreement with Westinghouse and Toshiba to settle for $2.168 billion. Of this $1.192 billion will go to SCE&G for its 55% ownership of the project, with $976 million to Santee Cooper, which owns 45%. Analysis of detailed schedule and cost data provided by Westinghouse and EPC subcontractor Fluor showed unit 2 would not be completed until December 2022 and unit 3 not before March 2024 – four years after the most recent completion date provided by Westinghouse. The overall project was 64.1% complete at the end of March 2017, and "about two-thirds" complete in July.

At the end of July Santee Cooper decided to halt construction in the light of “significant challenges” in completing the two reactors, notably uncertain costs, the uncertain availability of production tax credits, and reduced demand forecast. Also "the current political landscape has reduced the urgency for emissions-free base-load generation." It found that completing the project would cost the company $8 billion plus about $3.4 billion in interest, with schedule delays contributing to the increased interest. It had already spent $4.7 billion on construction and interest to date for its 45% share of the project. SCE&G had been evaluating options, including completion of only one unit, but concluded that completion of both units would be “prohibitively expensive” – about $9.9 billion for its 55% share of the project. SCANA said that completing only unit 2 would have resulted in a combined cost that was less than that previously approved by the South Carolina Public Services Commission under the fixed price option for completing the two nuclear units, but Santee Cooper’s decision ruled this out. “Ceasing work on the project was our least desired option, but this is the right thing to do at this time," and would accordingly apply to the state public services commission to permit this and allow it to recover from ratepayers about $4.9 billion it has spent.

Santee Cooper said that during the project wind-down it will continue to investigate the potential for federal support or "additional partners" that might make the project economic, and SCE&G echoed this. The state government then considered trying to sell Santee Cooper or take other action to revive the project, and SCE&G said in mid-August that it would withdraw its petition to the state public services commission, to allow for possible new partners. Duke Energy said it was not interested.

Westinghouse said: "The South Carolina economy is sure to feel the negative impact of losing over 5000 high-paying, long-term jobs, as well as not having available the reliable, clean, safe and affordable energy these units would provide. Also, at a time when other nuclear plants are being retired, the US energy sector is sure to feel the stunting impact of walking away from these two nuclear units."

In September 2017 the state governor released a report written 18 months earlier by Bechtel, highlighting eight significant contractual and management problems that required resolution*. The report detailed numerous recommendations, but suggested that the most important step for the consortium was to create a new "more achievable" project schedule.

Later in September 2017, SCANA and its subsidiaries received a federal subpoena for a broad range of documents related to the Summer plant expansion.

* The report found that some issues were to be expected due to the choice of reactor type – the project was due to be the first AP1000 reactor built in the USA – and the preceding hiatus in nuclear new build activity in the country. However it also highlighted the following eight significant contractual and management problems that required resolution:

- While the consortium's engineering, procurement and construction plans and schedules are integrated, the plans and schedules are not reflective of actual project circumstances.
- The consortium lacks the project management integration needed for a successful project outcome.
- There is a lack of a planned vision, goals and accountability between the owners and the consortium.
- The contract does not appear to be serving the owners or the consortium particularly well.
- The detailed engineering design is not yet completed, which will subsequently affect the performance of procurement and construction.
- The issued design is often not constructible, resulting in a significant number of changes and causing delays.
- The oversight approach taken by the owners does not allow for real-time, appropriate cost and schedule mitigation.
- The relationship between the consortium partners (Westinghouse Electric Company and Chicago Bridge & Iron) is strained, caused to a large extent by commercial issues.

In September 2020 Santee Cooper and Westinghouse finalised the terms of a settlement over ownership of equipment associated with the VC Summer plant. Earlier in May 2019, Santee Cooper had asked a New York bankruptcy court to dismiss Westinghouse’s claim of ownership of the same equipment. The two companies have now agreed to split the net sales proceeds for major non-installed nuclear equipment. For major installed nuclear equipment, Santee Cooper will receive 90% and Westinghouse 10%. For other equipment that could be used in other nuclear projects, 67% of the sale proceeds will go to Santee Cooper and 33% to Westinghouse. Santee Cooper has 100% ownership of the remaining project equipment. Westinghouse has responsibility for marketing the nuclear equipment. The marketing and sales effort will last for up to five years.

Design certification

As part of the effort to increase US generating capacity, the government and industry have worked closely on design certification for advanced Generation III reactors. Design certification by the Nuclear Regulatory Commission (NRC) means that, after a thorough examination of compliance with safety requirements, a generic type of reactor (say, a Westinghouse AP1000) can be built anywhere in the USA, only having to go through site-specific licensing procedures and obtaining a combined construction and operating licence (see below) before construction can begin. Design certification needs to be renewed after 15 years.

Designs now having US design certification and being actively marketed are:

- The Westinghouse AP1000, which is the first Generation III+ reactor to receive certification[c]. It is a scaled-up version of the Westinghouse AP600 which was certified earlier. It has a modular design to reduce construction time to 36 months. Four are in operation in China, and two are being built in the USA.
- The GE Hitachi advanced boiling water reactor (ABWR) of 1300-1500 MWe. Several ABWRs are now in operation and under construction in Japan. Some of these have had Toshiba involved in the

construction, and more recently it has been Toshiba that promoted the design most strongly in the USA.[d] Both the Toshiba and the GE Hitachi versions needed to have their design certification renewed from 2012. Toshiba withdrew its design certification renewal application in mid-2016.

- GE Hitachi's Economic Simplified BWR (ESBWR) of 1600 MWe gross with passive safety features, developed from the ABWR. GE Hitachi submitted the application in August 2005, design approval was notified in March 2011, and design certification was in September 2014. The first combined construction and operating licence (COL) with it was awarded for Fermi 3 in May 2015 and the second for North Anna 3 in June 2017.
- The Korean APR-1400 reactor, which is operating in South Korea since 2016 and in the United Arab Emirates since 2020. Korea Hydro & Nuclear Power submitted a design certification application to the NRC in October 2013 and the revised submission was accepted by the NRC in March 2015. The final safety report was published in September 2018 and design certification was given in May 2019.
- A demonstration unit of the NuScale multi-application small modular reactor (SMR), a 60 MWe integral PWR planned for Idaho National Laboratory. Subsequent deployment of 12-module power plants in western states is envisaged under the Western Initiative for Nuclear. The NRC accepted NuScale's design certification application in 2017. In August 2020 NuScale completed the sixth and final stage of the NRC design certification, and in September the NRC issued a standard design approval for a 50 MWe version, the first SMR to receive this. In 2013 NuScale secured up to $226 million of DOE support for the design, and applied for the second part of its loan guarantee in September 2017. The company is seeking separate approval for a 77 MWe version. Further details under the section on UAMPS below.

A reactor design expected to undergo US design certification:

- The Russian VVER-1200 reactor, which is operating at Novovoronezh II and at Leningrad II, may be submitted for US design certification through Rusatom Overseas, according to Rosatom.

Reactor designs formerly undergoing US design certification:

- The US Evolutionary Power Reactor (US EPR), an adaptation of Areva's EPR to make the European design consistent with US electricity frequencies. The main development of the type was to be through UniStar Nuclear Energy, but other US proposals also involved it. The application was submitted in December 2007 and the design certification rule was expected after mid-2015, with delays due to the complexity of digital instrumentation and control systems. Areva then delayed the NRC schedule and in March 2015 indefinitely suspended the application. The 1600 MWe EPR is being built in Finland, France, the UK and is operational at Taishan in China.
- The Mitsubishi US-APWR, a 1700 MWe design developed from that for a 1538 MWe reactor planned for Tsuruga in Japan. The application was submitted in December 2007 and certification was expected to be completed in February 2016, but Mitsubishi delayed the NRC schedule for “several years”. European certification for the almost identical EU-APWR was granted in October 2014. Two US-APWR reactors were proposed in the Luminant-Mitsubishi application for Comanche Peak, but Mitsubishi has withdrawn from this project.

Several designs of small modular reactors (SMRs) are proceeding towards NRC design certification application or the alternative two-step route of construction permit then operating licence:

- GE Hitachi Nuclear Energy submitted licensing documentation to the NRC in December 2019 for the BWRX-300. The company said the design "leverages the design and licensing basis of the NRC-certified ESBWR" and that it "represents the simplest, yet most innovative BWR design since GE began developing nuclear reactors in 1955."

- Holtec International announced in November 2020 that it had commenced licensing procedures with the NRC. A demonstration unit of the 160 MWe Holtec SMR-160 PWR (with external steam generator) is proposed at the Savannah River Site with DOE support, and a construction permit application is likely, or a similar application in Canada. In September 2016 Mitsubishi Electric Power Products and its Japanese parent became a partner in the project, to undertake the I&C design and help with licensing. In 2017 SNC-Lavalin joined the project. South Carolina and NuHub also back the proposal. In December 2023 Holtec International announced a new plan to build its first two SMR units – using the 300 MWe version of its SMR design, the SMR-300 – at its Palisades nuclear plant in Michigan. Holtec said it plans to file a construction permit application with the NRC by 2026 and has a target commissioning date for the first SMR-300 in the mid-2030s.
- South Carolina Electric & Gas is evaluating the potential of X-energy's Xe-100 pebble-bed SMR (50 MWe, a high temperature gas-cooled reactor) to replace coal-fired plants, in 200 MWe 'four-pack' installations.
- After pre-application talks since 2016, Oklo Inc submitted a COL application in March 2020 for its 1.5 MWe heatpipe microreactor, without first seeking design certification for it. The NRC accepted this application in June 2020. Oklo aims to build the first Aurora reactor at a site at Idaho National Laboratory for which the DOE has issued a site use permit. The fast neutron reactor will use high-assay low-enriched U-Zr metallic fuel.

In February 2014 the NRC said that its most optimistic scenario for awarding design certification for small reactors was 41 months, assuming they were light water types (PWR or BWR).

A fuller account of new reactor designs, including those certified but not marketed in the USA, is in the information page on Advanced Nuclear Power Reactors, or for the small modular reactors, in the page on Small Nuclear Power Reactors.

Early site permit

The 2001 early site permit (ESP) programme attracted four applicants: Exelon, Entergy, Dominion and Southern, for Clinton, Grand Gulf, North Anna and Vogtle sites respectively – all with operating nuclear plants already but room for more. In March 2007, Exelon was awarded the first ESP for its Clinton plant in Illinois, after 41 months' processing by the NRC and public review. The NRC then awarded ESPs to Entergy for its Grand Gulf site, Dominion for North Anna, and Southern for Vogtle. No plant type is normally specified with an ESP application, but the site is declared suitable on safety, environmental and related grounds for a new nuclear power plant. The last three of these 2001 ESPs were replaced by COL applications.

In March 2010, Exelon applied for an ESP for its Victoria County, Texas, site and withdrew the COL application for that project. In 2012 it withdrew the ESP application. PSEG Nuclear lodged an application for an ESP for a new reactor at its Salem/Hope Creek site on the Delaware River in New Jersey in May 2010, and this was granted in May 2016.

The seventh ESP application was for small reactors. Tennessee Valley Authority (TVA) submitted an ESP application to the NRC for its Clinch River small reactor project (for four units) in May 2016. The application was based on a plant parameter envelope encompassing the light-water SMRs currently under development in the USA by BWX Technologies, Holtec, NuScale Power and Westinghouse. It envisages that the emergency planning zone need extend only to the plant boundary. The ESP, supported by the DOE, was issued in

December 2019. TVA plans to submit a COL application with a view to building up to 800 MWe of capacity there.

Site use permits can be awarded by the DOE for its sites. In December 2019 Oklo Inc received a site use permit for its 1.5 MWe Aurora reactor to be built at Idaho National Laboratory.

Combined construction and operating licence

In 2003, the Department of Energy (DOE) called for combined construction and operating licence (COL) proposals under its Nuclear Power 2010 programme on the basis that it would fund up to half the cost of any accepted. The COL programme has two objectives: to encourage utilities to take the initiative in licence application; and to encourage reactor vendors to undertake detailed engineering and arrive at reliable cost estimates. For the first, DOE matching funds of up to about $50 million are available, and for the second, up to some $200 million per vendor, to be recouped from royalties.

Several industry consortia were created for the purpose of preparing COL applications for new reactors. By mid-2009, COL applications for 26 new units at 17 sites had been submitted to the Nuclear Regulatory Commission. A summary of submitted and expected applications is given in the Table below (US nuclear power reactors planned and proposed), and further information is given in Nuclear Power in the USA Appendix 3: COL Applications.

However, the only construction of new plants in the short term is in regulated markets, where costs can reliably be recovered.

Financial incentives

The Energy Policy Act (EPA) of 2005 introduced a production tax credit (PTC) of 1.8 cents per killowatt hour of electricity produced by new nuclear plants. The tax credit is available only for the first 6000 MWe of new nuclear capacity, and lasts only for the first eight years of operation. Companies cannot claim the PTC until assets begin generating electricity.

Under the terms of the EPA 2005, to qualify for the nuclear PTC, a plant must be in service on or before 31 December 2020, and the maximum value of the nuclear PTC is $6 billion over eight years (or $750 million per year). However in February 2018, an extension to the PTC was passed by the US Senate and Congress that allows reactors entering service after 31 December 2020 to qualify for the tax credits, and allows the US Energy Secretary to allocate credit for up to 6000 MWe of new nuclear capacity which enters service after 1 January 2021. The nuclear PTC is seen as an essential component for the completion of US plants already under construction and for first-of-a-kind small modular reactor (SMR) construction.

For further discussion see information page on US Nuclear Power Policy.

New nuclear capacity: further proposals

US nuclear power reactors proposed[e]

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Loan guarantee; start operation
Turkey Point 6&7, FL	AP1000	2 x 1250	Florida Power & Light	30/6/09, COL April 2017	
Fermi 3, MI	ESBWR	1600	Detroit Edison	18/9/08, COL issued May 2015	No decision to proceed
North Anna 3*, VA	ESBWR[f]	~1500	Dominion	20/11/07, COL issued June 2017, ESP issued	On hold from Sept 2017
Clinch River, TN	Uncertain, was mPower	2 x 360? up to 2 x 800	TVA	ESP application May 2016, issued Dec 2019	
Bellefonte 1&2[g, h], AL	B&W PWR (partly built)	2 x 1263	Nuclear Development LLC (sale pending from Tennessee Valley Authority)	30/10/07 for units 3&4[h] but COL withdrawn 2016	Seeking loan guarantee
Salem 3/Hope Creek, NJ	unspecified	1200?	PSEG Nuclear	ESP issued May 2016	
Dow's Seadrift site	Xe-100	4x80	X-Energy, Dow		
Subtotal proposed: 7 large units, 6 small (c. 10,500 MWe gross)					

Other proposals, suspended or cancelled

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Status
Victoria County, TX	ESBWR	3200	Exelon (merchant plant)	03/9/08 but withdrawn, ESP application 25/3/10, but withdrawn Oct 2012	
Piketon (DOE site leased to USEC), OH	US EPR	1710	Duke Energy		
Payette county, ID	APWR	1700	Alternate Energy Holdings Inc. (merchant plant)	Plans stalled since 2012	
Fresno, Ca	US EPR	1710	Fresno Nuclear Energy Group		
Amarillo, TX	US EPR	2 x 1750	Amarillo Power (merchant plant)		
Levy Country, FL	AP1000	2 x 1250	Duke Energy (formerly Progress Energy)	30/07/08, COLs approved Oct 2016 and cancelled April 2018	Project cancelled Aug 2017
Callaway[i], MO	Westinghouse SMR	5 x 225	Ameren Missouri	24/07/08 for EPR, then withdrawn; SMR proposal suspended	
Shearon Harris 2&3, NC	AP1000	2 x 1250	Duke Energy (formerly Progress Energy)	19/02/08, COL suspended May 2013	
Grand Gulf, MS	ESBWR[i]	1600	Entergy	27/02/2008, COL application withdrawn 9/15, ESP issued	
Comanche Peak, TX	US-APWR	2 x 1700	Luminant (merchant plant)	19/09/08, COL suspended 11/13	
Bell Bend (near Susquehanna), PA	US EPR	1710	PPL/Talen (merchant plant)	10/10/08, COL review suspended 2014 but EIS approved. COL application withdrawn Aug 2016	Suspended indefinitely

Site	Technology	MWe gross	Proponent/utility	COL lodgement & issue dates	Status
Calvert Cliffs*, MD	US EPR	1710	UniStar Nuclear (merchant plant)	07/07 and 03/08, terminated in 2012, COL application withdrawn 07/15	Refused an offered loan guarantee, needs US equity
Green River, UT	AP1000	2 x 1250	Blue Castle / Transition Power Development		2030
River Bend, LA	ESBWR	1600	Entergy	25/09/08, COL application withdrawn	
South Texas Project[e], TX	ABWR	2 x 1356	Toshiba, NINA, STP Nuclear (merchant plant)	COLs issued Feb 2016 but design certification application withdrawn July 2018	Cancelled May 2018
Nine Mile Point, NY	US EPR	1710	UniStar Nuclear (merchant plant)	30/09/08, COL application withdrawn 2013	
Stewart County, GA	AP1000	1250	Georgia Power (Southern Co)	COL application deferred in 2017	Build after 2030
William States Lee III, SC	AP1000	2 x 1250	Duke Energy	13/12/07, COL issued Dec 2016	Plans cancelled Aug 2017

Construction was also well under way at Summer, South Carolina, but this project has now been cancelled – see section above.

Westinghouse bankruptcy

Westinghouse filed for Chapter 11 bankruptcy reorganization on 29 March 2017, after struggling to find cash to fund growing cost overruns at its two US nuclear plant projects (see above). The company listed assets of $4.3 billion and liabilities of $9.4 billion in the filing, and asked permission to pay about $50 million in employee salaries and benefits as well as $87.3 million to critical vendors during bankruptcy proceedings. Westinghouse and 30 affiliated companies filed for bankruptcy protection, listing about 35,000 creditors involved. Westinghouse said that its operations in Asia, Europe, the Middle East and Africa were not affected by the bankruptcy filings. Interim financing of $800 million was provided by Westinghouse parent company Toshiba and a New York private equity company, Apollo Capital Management. Toshiba said that it anticipated a new entity to be found by Westinghouse would take a leading role in bringing that company out of bankruptcy, and that its own control of Westinghouse had ended.

Westinghouse said its largest creditors were US construction company Fluor Enterprises – which was brought into the US nuclear plant projects in 2015 to take over construction management, and Chicago Bridge & Iron – in connection with the acquisition by Westinghouse of CB&I's Stone & Webster construction business in late 2014. Fluor was owed almost $194 million, and CB&I $145 million. In March Toshiba said it would not provide additional funding without collateral, according to the bankruptcy protection filing. That resulted in the development of the debtor-in-possession financing, under which Westinghouse funded continuing operations. Westinghouse said it would work with the several owners of the nuclear plant projects in Georgia and South Carolina to "explore the continued feasibility of those projects in a manner that is cost-neutral and cash-neutral" to Westinghouse and its affiliates. Those owners of the Vogtle and Summer plants agreed to pay costs to continue construction themselves for a transition and evaluation period while final arrangements on future plant work were developed. The project at Summer has since been abandoned.

Westinghouse said that it remained committed to the AP1000 technology and would continue to support plants that were then being built in China, and planned for China, USA, India, Turkey, the UK and elsewhere. Its nuclear fuel business had revenues of $1.48 billion in fiscal 2015 (to end March 2016), and its operating plant business had revenues of $1.65 billion in the same period, while the new nuclear plant services business lost money.

Bellefonte

Tennessee Valley Authority had a pair of uncompleted 1213 MWe PWR reactors: Bellefonte 1&2. Construction on these units was abandoned in 1988 after $2.5 billion had been spent and unit 1 largely (88%) completed and unit 2 about 58% completed. In February 2009, the NRC reinstated the construction permits for these (and later the status of the reactors classified as 'deferred'). Today unit 1 is considered no more than 55% complete due to the transfer or sale of many components and the need to upgrade or replace others, such as the instrumentation and control systems, reactor pressure vessel, steam generators and main condenser tubing. In August 2011 TVA opted to complete unit 1 at a cost of about $4.9 billion rather than building a new AP1000 reactor as unit 3* (see Appendix 3: COL Applications). TVA then asked the NRC in 2011 to defer consideration of its COL for units 3&4 (AP1000 option), and in February 2016 it withdrew the COL application.

* In August 2010, TVA had committed to spending $248 million in the year to September 2011 towards work at Bellefonte[8] and an engineering contract was awarded to Areva SA in October 2010 for work on unit 1, including engineering, licensing and procurement of long-lead materials in support of a possible start-up date in the 2018-19 timeframe. Following TVA's 2011 decision to proceed, the Areva contract included construction and component replacement work on the plant's nuclear systems, a digital instrumentation and control (I&C) system, a modernized control room, a plant simulator for personnel training plus fuel design and fabrication. Areva contracts amounted to some $1 billion, with heavy construction to start when Watts Bar 2 was completed. In late 2013 TVA revised the estimated cost to $7.4 to $8.7 billion.

However, TVA’s 20-year integrated resource plan in 2015 did not have Bellefonte 1&2 as a firm prospect, and it projected 2028 completion of unit 1 as having the effect of increasing system costs. Later in 2015 the company said it would defer consideration of completing unit 1 for a decade. In May 2016 the TVA board decided to offer the plant for sale at auction, and in November Nuclear Development LLC agreed to buy it for $111 million.

Nuclear Development said it intended to invest up to $13 billion from 2017 to complete the plant, and it was lobbying for a $5 billion loan guarantee. Bellefonte is a regulated plant, with guaranteed cost recovery. In mid-2018 the company signed an agreement with SNC-Lavalin to finish building the plant once the purchase is completed. Completion of unit 1 was then anticipated in 2024. In November 2018 Nuclear Development applied to the NRC to transfer the construction permits and announced its intention to involve Framatome in the project, but late in 2019 the NRC had not yet undertaken a review of the application. The sale is contingent upon NRC approval, and the company said that construction depends both on a loan guarantee (it was seeking $8.6 billion) and securing power purchase agreements.

Lee

Duke Energy lodged a COL application in December 2007 for two Westinghouse AP1000 units for its William States Lee III plant at a new site near Charlotte in Cherokee County, South Carolina, to provide power for North Carolina. The company was seeking a loan guarantee and was considering regional partnerships to build the plant. The environmental review for NRC was completed in December 2013, showing no problems, the safety evaluation review was completed in August 2016 and the COLs issued in December 2016. Duke told NRC in 2012 that it was revising its COL application to move the nuclear island of both Lee units by some 20 metres to make excavation and construction easier. Duke had spent $471 million on licensing, planning and pre-construction activities for the plant to February 2016. If proceeding, the 1117 MWe (net) units were then expected online in 2024 and 2026. In August 2017 the company announced: "The risks and uncertainties to initiating construction on the Lee nuclear project have become too great, and cancellation of the project is the best option for customers." It is maintaining its licence to build at the site in the future.

Turkey Point 6&7

NextEra Energy subsidiary Florida Power & Light (FPL) applied in June 2009 for a COL for two Westinghouse AP1000 reactors at Turkey Point in Florida where two 693 MWe PWR units (3&4) are operating and were uprated in 2012-13. (Unit 5 is a 1190 MWe combined cycle gas plant; units 1&2 are 400 MWe oil/gas units.) In 2011 the Florida Public Service Commission approved a levy towards construction of the reactors, and in May 2014 the state government approved the project, with new transmission lines.

The company said in April 2014 that it expected to start operation of the first new unit in June 2022 and the second a year later, but in January 2015 changed this to 2027 and 2028, due to “NRC licensing schedule adjustments and changes to the Florida nuclear cost recovery law,“ which delay the start of site works. The COL was approved by the NRC in April 2018.

South Texas Project 3&4

Units 3&4 at South Texas Project (STP) were envisaged as a merchant plant with two 1356 MWe Advanced Boiling Water Reactors (ABWR)[j]. The COL application was submitted in September 2007 by site operator STP Nuclear Operating Company (STPNOC) on behalf of the project owner, which was then a 50:50 partnership between NRG Energy and the City Public Service Board (CPS Energy) of San Antonio. Ownership of STP units 1&2 (Westinghouse PWRs) is Constellation Energy (44%) – which purchased NRG Energy’s share in November 2023 – CPS Energy (40%) and Austin Energy (16%).

In March 2008, NRG with Toshiba subsidiary Toshiba America Nuclear Energy (TANE) formed Nuclear Innovation North America (NINA – 88% NRG; 12% TANE) to develop the project. In February 2009, TANE entered into an engineering, procurement and construction (EPC) agreement that would convert into a turnkey contract once the final decision to proceed with the project had been taken. Following TANE's later announcement that the project would cost $4 billion more than the $13 billion that was previously estimated, in February 2010 CPS Energy decided to reduce its stake to 7.625%, with NINA increasing its share to 92.375%.

In May 2010, Japanese utility Tokyo Electric Power Company (Tepco), which had been acting as technical consultant to the project, agreed to take 10% of NINA's stake for $155 million, with an option to later double its holding. The deal was conditional on a DOE loan guarantee being awarded to the project. However, in April 2011, based largely on low natural gas prices in Texas compounded by the March 2011 accident at Tepco's Fukushima Daiichi plant in Japan, NRG decided to pull out of the project and write off its $331 million investment in it. Toshiba had spent $150 million and persevered with the project, though it wrote off $305 million (JPY 31 billion) on NINA in 2014. NINA was dissolved in 2018.

COLs for each of the two units were issued in February 2016.[k] However, Toshiba’s withdrawal of the application for design certification renewal in mid-2016 effectively put the project on hold. In May 2018, Toshiba announced its withdrawal from the project, stating that it was no longer financially viable. Toshiba said its decision to exit the project was in line with its policy "to eliminate risk from the overseas nuclear power business, particularly from construction-related cost overruns in nuclear power plant construction projects." Toshiba stated it had sought, but failed to find investors to participate in the project.

UAMPS

The UAMPS Carbon-Free Power Project, a six-module Nuscale SMR plant at the Idaho National Laboratory, would be owned by Utah Associated Municipal Power Systems (UAMPS) that comprises 48 members from Utah, California, Idaho, Nevada, New Mexico and Wyoming. UAMPS plans to submit a COL application by April 2023. In 2013 NuScale secured up to $226 million DOE support for the original 45 MWe design. The DOE has granted permission to site the plant on the 2300 square km Idaho National Laboratory estate, reportedly in the southern part of it. Under this agreement UAMPS had ten years to begin operating the first module, and this will trigger a 99-year lease for the plant.

In October 2020 the DOE approved a $1.335 billion cost-share award, allocated over 10 years, to a special purpose entity wholly-owned by UAMPS – the Carbon Free Power Project, LLC – for the development and construction of the planned six-module plant (then 60 MWe per module). The award represents around one-quarter of the development and construction costs over ten years. Projected LCOE was about $55/MWh. In November 2020, the module power was uprated to 77 MWe, lowering the overnight capital cost from $3600/kWe to $2850/kWe, according to NuScale.

However, a UAMPS meeting held in October 2022 indicated significantly higher costs for the projcet than first estimated. Inflationary pressures, such as the rising price of steel could push the power cost from $55/MWh to between $90 and $100 per MWh.

In November 2023 UAMPS announced that it had mutually agreed to cancel the CFPP due to the inability to reach the necessary 80% subscription rate required to support the development.

Fermi 3

This is a reference unit for GE Hitachi's ESBWR design, proposed by Detroit Edison in Michigan, but the company has not yet committed to proceeding. A COL application was made in 2008 and environmental approval was received in January 2013. Full design certification of the ESBWR in 2014 allowed the safety evaluation to proceed, and the COL was approved in May 2015.

Levy County, Florida

Site works started for two 1200 MWe Westinghouse AP1000 reactors on a greenfield site in Florida, and to January 2012 some $860 million had been spent on this. The company expected to have spent about $1 billion on the design, acquisition of heavy equipment and site works by the time it secures NRC approval. In September 2008, Progress Energy Florida signed an EPC contract with Westinghouse and The Shaw Group (now CB&I) consortium. The contract is for $7.65 billion ($3462/kWe), of an overall project cost of about $14 billion.

In August 2013 Duke Energy resolved to terminate the 2008 EPC contract as "a result of delays by the NRC in issuing COLs for new nuclear plants, as well as increased uncertainty in cost recovery caused by recent legislative changes in Florida.” It continued to pursue the COLs in order to keep the option open. In April 2014 Duke announced plans to build 2745 MWe of gas-fired capacity by 2021 instead of proceeding with the Levy County nuclear plant in the original timeframe. Duke Energy Florida was planning to sell all the long-lead time equipment it had ordered by the end of 2014, but it was in dispute with Westinghouse over EPC contract termination. In October the Florida Public Service Commission ordered Duke to repay to ratepayers $54 million it had collected in advance to fund the 'cancelled' project. In October 2016 the NRC approved the COLs.

The last estimated operational dates were 2024-25, the delay being due to "lower-than-projected customer demand, the lingering economic slowdown, uncertainty regarding potential carbon regulation and current low natural gas prices." The revised cost was $19-24 billion. It would be a regulated plant, with guaranteed cost recovery. In August 2017 Duke Energy cancelled the project, citing the Westinghouse bankruptcy and slowing energy demand, and said it would not maintain the licences.

North Anna 3

In December 2010, Dominion announced that it had agreed with Mitsubishi Heavy Industries to build a US-APWR unit, but in April 2013 Dominion announced that it had reverted to the ESBWR as preferred technology (as originally selected in 2005), and would amend its COL application accordingly. The COL for the ESBWR was issued in June 2017. Dominion quotes 1453 MWe net (summer capacity) for the unit there. In May 2013 it agreed a construction contract with GE Hitachi and Fluor, conditional upon proceeding. Dominion said it will make a decision on building in due course, and hence it remains as 'proposed' according to the World Nuclear Association. Dominion suggests start-up in 2028 if it proceeds. It had spent $345 million on the project to early 2016. It is a regulated plant, with guaranteed cost recovery. A consultant to the state has estimated the cost of the plant as $19.3 billion including financing, or $13,283/kW, and Dominion has said that such a figure would not be unreasonable.

Clinch River

Babcock & Wilcox (B&W) has set up B&W Modular Nuclear Energy LLC to market the mPower small modular reactor design of 180 MWe. In February 2013 B&W signed an agreement with TVA to build up to four units at Clinch River, with design certification application intended to be submitted to the NRC in 2015. Bechtel has joined the project as an equity partner to design, license and deploy it. As well as TVA, First Energy and Oglethorpe Power are involved with the proposal for Oak Ridge, Tennessee. TVA submitted an early site permit (ESP) application in May 2016, with no particular technology specified. The ESP was issued in December 2019.

Harris 2&3

Progress Energy lodged a COL application for two AP1000 units at its Shearon Harris site at New Hill in North Carolina in February 2008. This was proceeding towards being granted at the end of 2014. Expansion of the plant would require raising the water level of Harris Lake by 6 metres, and relying on the Cape Fear River as backup cooling water. However, in May 2013 Duke Energy (which had taken over Progress) asked NRC to suspend the COL review due to projected electricity demand being low for next 15 years.

Comanche Peak

Luminant planned to use two US-APWR units for its merchant plant in Texas. In May 2011 the NRC concluded that there were no environmental considerations that would hinder the project. Luminant's loan guarantee application was accepted by DOE and it was understood that this was the first alternative to the four shortlisted projects, two of which are now not proceeding for the time being. The application for design certification was submitted in December 2007 and certification was expected to be completed in February

2016, but Mitsubishi delayed the NRC schedule for “several years”. Meanwhile Mitsubishi has withdrawn as a joint venture partner.

Calvert Cliffs 3

Unistar, now owned by EdF, planned to build a 1710 MWe Areva US-EPR alongside Constellation's units 1&2, as a merchant plant. Exelon, merging with Constellation (in which EdF has 49.9% equity) said in November 2011 that with the advent of shale gas, a new nuclear plant at Calvert Cliffs was "utterly uneconomic" by a factor of about two.

The design certification application was submitted in December 2007 and the design certification rule was expected after mid-2015, with delays due to the complexity of digital instrumentation and control systems. Areva then delayed the NRC schedule and in March 2015 indefinitely suspended the application.

Salem 3

PSEG was issued in May 2016 with an early site permit for up to two new Salem reactors at Hope Creek, NJ. No reactor technology was specified.

Other planned or proposed new US nuclear capacity is described more fully in Appendix 3: COL Applications.

Electricity market challenges

About 54 GWe of US nuclear capacity is in regulated markets, and 45 GWe in deregulated merchant markets, with power sold competitively on a short-term basis. In these liberalized markets, regional transmission organisations (RTOs) and independent system operators (ISOs) operate the grid, using free-market auctions and longer-term power purchase agreements under federal arrangements and rules. See Nuclear Energy Institute's list of nuclear plants in regulated and deregulated states.

In states with deregulated electricity markets, nuclear power plant operators have found increasing difficulty with competition on two fronts: low-cost gas, particularly from shale gas developments; and subsidized wind power with priority grid access. The imposition of a price on carbon dioxide emissions would help in competition with gas and coal, but this is not expected in the short-term. Single-unit plants which tend to have higher operating costs per MWh are most vulnerable. The basic problem is low natural gas prices allowing gas-fired plants to undercut power prices. A second problem is the federal production tax credit of $23/MWh paid to wind generators, coupled with their priority access to the grid. When there is oversupply, wind output is taken preferentially. Capacity payments can offset losses to some extent, but where market prices are around $35-$40/MWh, nuclear plants are struggling. According to Exelon, the main operator of merchant plants and a strong supporter of competitive wholesale electricity markets, low prices due to gas competition are survivable, but the subsidized wind is not. Although wind is a very small part of the supply, and is limited or unavailable most of the time, it has a major effect on electricity prices and the viability of base-load generators.

A significant ISO for nuclear plants is PJM Interconnection which serves all or parts of 13 mid-Atlantic states and DC. In May 2014 five Exelon reactors at three plants – Oyster Creek, Quad Cities and Byron – for the first time failed to clear the PJM capacity auction for three years ahead, 2017-2018, so did not receive capacity payments or an assured market for 12 months, despite having been a reliable basis of supply in New Jersey and Illinois for decades, and of zero-carbon sources. Following the 2014 auction, FERC said it was actively considering ways it can ensure that base-load power sources, such as nuclear plants, are appropriately valued and their viability maintained in wholesale electricity markets. FERC's focus is on capacity markets and how they should take into account the full value of a base-load power plant; and on whether there are appropriate incentives for plants that contribute to the country's electric reliability in order for them to survive and continue providing those services.

In May 2017 Exelon's Three Mile Island (TMI) unit 1 and Quad Cities 1&2 failed to clear the PJM Interconnection capacity auction for 2020-21. Its other plants did clear in the auction, which cleared about $25 per megawatt-day below the previous year and $15 below market expectations at $76.53/MWd for the majority of the PJM footprint due to lower load forecasts and other factors. Exelon said that its nuclear units cleared a total of 13,275 MWe of capacity in the auction. Clearing prices for that capacity ranged from $188/MWd in the ComEd region serving Chicago, where Quad Cities is located, to $77/MWd in the RTO region. In TMI's region, the price was $88/MWd. Exelon said that TMI 1 had not cleared the past three PJM auctions and had not been profitable in five years. While the continued operation of Quad Cities was ensured by newly-introduced legislation in Illinois, Exelon warned that the TMI reactor, which entered service in 1974, was at risk of early retirement.

In May 2018, PJM's 2021-22 capacity market auction cleared at $140/MWd, an 83% increase over the 2017 auction. Despite the higher price, just 19 GWe of nuclear cleared, a decrease of 7.4 GWe from the previous year. Exelon said that TMI 1, Dresden and "all but a small portion" of its Byron plant failed to clear. FirstEnergy, despite announcing retirement plans for 4 GWe of nuclear capacity in March, was required to offer the units into the auction – but none cleared. Exelon shut down TMI 1 in September 2019, but in July 2024 Constellation was in talks to restart the unit.

In May 2021, PJM's 2022-23 capacity market auction cleared at $50/MWd, well down on the 2021-22 auction due to a lower load forecast among other factors. Despite the lower price, nuclear utilities cleared an additional 4.5 GWe compared to the previous auction.

Early reactor retirements

In November 2015 Exelon said that its Clinton, Ginna and Quad Cities plants were at greatest risk of early retirement for economic reasons, with a question mark also over Byron. In May 2016 Exelon said it would close Clinton in June 2017 and Quad Cities in June 2018 unless the state of Illinois made provision for them to be profitable, by means of zero emission credits, likely to be capped at 20 TWh/yr for the 2884 MWe. New York state is making similar provision for its upstate plants (see below).

In June 2016 Omaha Public Power decided to close Fort Calhoun in Nebraska, the smallest US nuclear power plant, at the end of the year. PG&E in June 2016 announced that the Diablo Canyon units would close in 2024 and 2025. In March 2023 the NRC approved PG&E's request to operate the two units at Diablo Canyon past their respective 2024 and 2025 licence expiry dates on the condition that PG&E submitted licence renewal applications for the units by the end of 2023. The application for the two units was accepted by the NRC in December 2023.

Early in 2017 Entergy and the state of New York agreed that unit 2 of the Indian Point plant would close by the end of April 2020, followed by unit 3 in April 2021. Energy cited "sustained low current and projected wholesale energy prices that have reduced revenues, as well as increased operating costs" coupled with political pressure. Entergy had invested over $1.3 billion in the two reactors over the 15 years it owned them. Its application for licence renewal of the two units was proceeding very slowly through the NRC review. In September 2018 the NRC approved Entergy's request to shorten the term of renewed operating licences for units 2 and 3 to 2024 and 2025 respectively. Unit 2 closed on 30 April 2020, and unit 3 on the same day a year later.

In September 2017 Entergy announced that it will keep its Palisades nuclear plant in Michigan open until 2022. The company had previously announced in December 2016 that it planned to close the 789 MWe net unit in October 2018 due to economic factors in the partly deregulated market. The reactor was shut down in May 2022 and sold to Holtec International in June for decommissioning. In light of the DOE's publication of its Civil Nuclear Credit Program – aiming to keep marginal units in deregulated environments online to help accelerate the US energy transition – in September 2022, Holtec international began exploring the possibility of restarting the plant. In November 2022 the DOE rejected Holtec's application that sought funding under the Civil Nuclear Credit Program to reactivate Palisades. The following month, Holtec announced plans to launch a second attempt to secure federal funding to restart the unit. In January 2023 the Board of Commissioners of Allegan County, Michigan voted unanimously in favour of Holtec's bid to obtain federal funding to restart the unit. In March 2023 Holtec applied for federal funding from the DOE under the Civil Nuclear Credit Program to restart the Palisades plant, which it believes would cost more than $1 billion. In September 2023 a long-term power purchase agreement was agreed between Palisades Energy and Wolverine Power Cooperative. Later that month, Holtec applied to the NRC for reauthorization of power operations at the plant. Also in the same month, Wolverine Power Supply submitted an application for funding through the US Department of Agriculture's Empowering Rural America (New ERA) $9.7 billion grant and loan initiative that is funded by the Inflation Reduction Act.

In September 2018 Exelon's single-reactor Oyster Creek plant in New Jersey was shut down, 11 years before its operation was due to end, so as to avoid the expense of state environmental regulations that would require the construction of $800 million cooling towers.

In May 2019, Entergy's 677 MWe single-reactor Pilgrim plant in Massachusetts was shut down due to market conditions and increased costs, the same situation as caused Entergy to close its 635 MWe Vermont Yankee reactor at the end of 2014, and plan to close its 852 MWe Fitzpatrick reactor in January 2017.

Three Mile Island 1 was shut down in September 2019 due to economic challenges (see above). Although the unit had been licensed to operate until 2034, Exelon had announced in May 2017 that it would be closed if policy reforms recognising nuclear as a low-carbon electricity producer were not enacted.

In August 2020, Exelon announced that it intends to retire its Byron and Dresden plants in Autumn 2021. Units 2&3 of the Dresden plant are licensed to run for a further 10 years, and units 1&2 of the Byron plant are licensed to run for a further 20 years. Exelon stated that the plants face revenue shortfalls amounting to "hundreds of million dollars" due to declining energy prices and market rules that allow fossil fuel plants to underbid clean resources in the PJM capacity market. Exelon also stated that its LaSalle and Braidwood plants were also at risk of premature closure. However, in September 2021 a new energy bill was signed into law in Illinois, which introduced $694 million in nuclear subsidies to be paid over 5 years*. Exelon subsequently announced that it was to refuel its Byron and Dresden plants.

* The bill also included subsides of more than $350 million annually for renewables.

Prematurely retired reactors

Reactors	State	Net capacity (MWe)	Shutdown
Crystal River 3**	FL	860	2013
San Onofre 2&3**	CA	1070, 1080	2013

Reactors	State	Net capacity (MWe)	Shutdown
Kewaunee	WI	566	2013
Vermont Yankee	VT	605	2014
Fort Calhoun	NE	482	2016
Oyster Creek 1	NJ	619	2018
Pilgrim 1	MA	677	2019
Three Mile Island 1	PA	819	2019
Indian Point 2	NY	998	2020
Duane Arnold	IA	601	2020
Indian Point 3	NY	1030	2021
Palisades	MI	805	2022
Total		**11,092**	

Source: Nuclear Energy Institute
** Crystal River 3 closed after the operator, Duke Energy, decided against trying to repair a delamination within the containment concrete that had been discovered during uprate work. San Onofre 2&3 closed due to faults with the steam generators that were installed a year prior as part of an uprate programme at the plant.

Plants saved from premature retirement

Reactors	State	Net capacity (MWe)	Initially announced shutdown year
Beaver Valley 1&2	PA	908, 905	2021
Byron 1&2	IL	1164, 1136	2021
Clinton	IL	1062	2017
Davis-Besse	OH	894	2020
Dresden 2&3	IL	894, 879	2021
FitzPatrick	NY	813	2017
Hope Creek & Salem 1&2	NJ	1172, 1169, 1158	2020-2021
Millstone 2&3	CT	869, 1210	2020
Nine Mile Point 1&2	NY	613, 1277	2017-2018
Perry	OH	1240	2020
Quad Cities 1&2	IL	908, 911	2018
R. E. Ginna	NY	560	2017
Total		**19,742**	

Source: Nuclear Energy Institute

EPA Clean Power Plan

In June 2014 the US Environmental Protection Agency (EPA) announced that it would use its authority under the Clean Air Act to require a reduction in carbon emissions from US power plants of 25% below 2005 levels by 2020, and more by 2030, with states to be responsible for achieving this. There had already been a 16% drop since 2005. In August 2015 the EPA issued its Clean Power Plan to curb greenhouse gas emissions from existing fossil fuel-fired power plants under section 111(d) of the Clean Air Act and to reduce CO_2 emissions by 32% from 2005 levels by 2030. The Plan became effective in December 2015, and states were to have until September 2018 to submit their plans to comply with the emission reductions, using various means including increased thermal efficiency by 2.1-4.3%, greater use of nuclear power and renewables, and greater use of gas.

In November 2014 the National Association of Regulatory Utility Commissioners urged the EPA, in its proposed Clean Power Plan, to adopt regulations which "encourage states to preserve, life-extend, and expand existing nuclear generation." In January 2015 the Nuclear Energy Institute said that a top priority was for nuclear plant operators to be fully compensated in competitive wholesale US electricity markets for the value they provide as the main source of reliable, carbon-free, continuous base-load power. However, the majority of these measures were not included and the Clean Power Plan was heavily biased to wind and solar renewables. It allowed credit for new nuclear power plants and uprates to existing units, but would not credit the role of existing nuclear capacity, some of which is marginal economically in present market conditions. Nor would it credit nuclear licence extensions on the same basis as new capacity. Nuclear power produces about 55% of US carbon-free electricity, nuclear plants are already the main carbon-free generation source for over half of US states, and they avoid the emission of over 750 million tonnes of CO_2 per year relative to coal. It is accepted that the 32% CO_2 reduction by 2030 will be impossible without at least the present level of nuclear contribution. About one-third of the nation's 300 GWe of coal-fired base-load capacity is expected to be retired by 2030. Some states were preparing legal challenges to the Plan, others remain committed to it.

In March 2017 President Trump signed the Energy Independence Policy executive order which aimed to roll back the 2015 EPA Clean Power Plan, and called for the EPA to review it to remove what may "unduly burden the development of domestic energy resources." The impact of this could not be immediate, and may be more in tone than substance. It would take several years under notice and comment rulemaking processes, and the main timeline under the Plan was 2030 in any case. US electricity should be "affordable, reliable, safe, secure, and clean," presumably in that order of priority. The executive order rescinded several climate change measures. In October 2017 the EPA issued a notice of proposed rulemaking (NOPR) to repeal the Clean Power Plan on the grounds that it exceeds the EPA's authority under the Clean Air Act and sets emissions standards that power plants could not reasonably meet. Repeal of the plan, which was premised on a "novel and expansive view of Agency authority," would save $33 billion in compliance costs by 2030 according to the EPA. The plan was repealed in June 2019.

In November 2020 the USA formally withdrew from the Paris Agreement. On 20 January 2021, the first day of the Biden administration, the country rejoined the agreement.

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative is a 2009 cap-and-trade programme for reducing carbon dioxide emissions, covering fossil-fuel plants above 25 MWe in the northeast and mid-Atlantic states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and (from January 2021) Virginia. Pennsylvania is expected to join in 2022. Carbon dioxide emissions allowances are auctioned quarterly, with current prices around $7/tonne.

Electricity market reforms

State initiatives, zero-emission credits

A number of states are taking action to counteract problems with the markets, which the states do not control, to preserve values not recognized in the markets.

New York

In December 2015 the New York state governor directed its Department of Public Service (NYDPS) to develop a clean energy standard (CES) that calls for a 40% reduction in greenhouse gas emissions from 1990 levels by 2030 and a longer-term decrease of 80% by 2050, while not losing carbon reduction gains achieved to date. The state intended to comply with the EPA Clean Power Plan, and its six nuclear reactors provided nearly one-third of the state's electricity in 2015. Entergy had announced the premature closure of its FitzPatrick nuclear plant in upstate New York by January 2017, and Exelon had warned its Ginna and Nine Mile Point plants were at risk of closure for similar economic reasons. The governor said that closing nuclear facilities "would eviscerate the emission reductions achieved through the state's renewable energy programmes, diminish fuel diversity, increase price volatility, and financially harm host communities." The New York independent system operator later warned that to preserve the reliability of the grid, the state must keep all of its nuclear plants operating while slowing renewable energy growth.

The NYDPS issued a white paper in January 2016 proposing 'zero-emission credits' (ZECs) for nuclear generators that would work in parallel with the tax credits that renewable sources receive, and provide the market signals necessary to warrant continued operation of these non-emitting plants. The Nuclear Energy Institute noted that the proposal "establishes a mechanism that can ensure nuclear operators receive the market signals necessary to warrant continued operation of these non-emitting assets." In addition, a cost study issued by the NYDPS in April 2016 as a supplement to the white paper showed the "outstanding value" that including nuclear in the clean energy standard would provide to New York citizens. The study pointed out that the zero-emission credits would generate $2.8 billion in benefits, or two-thirds of the entire clean energy standard programme's $4.4 billion, for $270 million (less than 8% of the programme's costs).

In July 2016 the NYDPS put forward a proposal which would value the zero-emissions attributes of the upstate nuclear power plants (*i.e.* not including Indian Point), based on the social cost of carbon and requiring the distribution utilities "to pay for the intrinsic value of carbon-free emissions from nuclear power plants by purchasing zero-emission credits." The department said that there is a "public necessity" for subsidies for the Fitzpatrick, Ginna and Nine Mile Point plants. The benefits of paying such subsidies would far outweigh the costs, the department said. During the first two years of the programme, the state's economic and environmental benefits associated with carbon reductions, supply cost savings and property tax benefits were estimated to be about $5 billion, against total payments of up to $965 million – a net benefit of $4 billion.

The NY Public Service Commission on 1 August 2016 approved the CES plan, but excluded Indian Point. The majority vote was reported to be on three main criteria: grid reliability, reducing carbon emissions, and maintaining jobs. The governor's announcement said: "A growing number of climate scientists have warned that if these nuclear plants were to abruptly close, carbon emissions in New York will increase by more than 31 million metric tons during the next two years, resulting in public health and other societal costs of at least $1.4 billion."

New York's ZEC programme is being implemented in six tranches over a period of 12 years from April 2017. For the first two-year period nuclear generators received ZECs of $17.54/MWh, paid by the distribution utilities (and hence eventually ratepayers) but otherwise similar to the federal production tax credits (PTC) applying to renewables since 1993 on an inflation-adjusted basis, though at a lower rate than its $23/MWh for wind. ZECs will escalate to $29.15/MWh over subsequent years. Later, in July, Entergy's Indian Point plant was included in the proposal, albeit not for the first two years.

The broader CES required that NY state's utilities source at least half their electricity from renewables by 2030, less than it gets now from all clean energy sources: nuclear 32%, hydro 19%, wind 3%, and solar (less than 1%). Gas supplies 40% of power. In 2019 the CES was revised to require 100% carbon-free electricity by 2040.

In August 2016 Exelon agreed to buy the 838 MWe Fitzpatrick plant, which is licensed to 2034, from Entergy for $110 million in anticipation of the NYPDS CES proposal being implemented. It also confirmed that it would proceed with investing about $200 million in Nine Mile Point and Ginna plants early in 2017 and would "invest hundreds of millions of dollars in Fitzpatrick in January to refuel the plant and upgrade systems needed to reverse the shutdown decision." Entergy said it plans “to move away from merchant power markets and toward a company operating exclusively as a utility in regulated markets.”

In October 2016 a coalition of non-nuclear energy companies and groups filed a lawsuit against the New York Public Service Commission challenging the PSC's authority to raise electricity rates to pay for the ZECs which will subsidize the continued operation of several nuclear power plants. The plaintiffs, led by the Coalition for Competitive Electricity, included Dynegy, Eastern Generation, Electric Power Supply Association, NRD Energy, Roseton Generating and Selkirk Cogen Partners. This legal challenge failed, and an appeal to the Supreme Court challenging the ZEC programme was rejected in April 2019.

Illinois

In February 2015 Illinois, another state with a deregulated market, took steps to enhance the competitiveness of nuclear power and renewables. The Illinois Low Carbon Portfolio Standard would require utilities to purchase low-carbon energy credits equivalent to 70% of their retail sales to customers within the state. This was congruent with the subsequent EPA Clean Power Plan. Eleven Exelon nuclear reactors at six sites supply almost half of the state’s electricity. In mid-2016 the legislation had lapsed. Following the failure of Illinois legislature to pass its Next Generation Energy Plan, in June 2016 Exelon said that it would move forward with plans to close down Clinton in June 2017 and Quad Cities a year later. It would terminate capital investment projects required for the long-term operation of both plants, and would immediately take one-time charges of $150 million to $200 million for 2016, and accelerate some $2 billion in depreciation and amortization.

In October 2016 Exelon confirmed that it would close the Quad Cities and Clinton plants if legislation was not passed by year end since they had lost more than $800 million in the past seven years. In November the Future Energy Jobs Bill was introduced, reflecting “a diverse set of interests, as well as agreement in important areas among environmentalists, consumer advocates, community leaders and energy companies.” A core feature of the legislation is the establishment of the Zero Emission Standard to preserve the state’s two at-risk nuclear plants, saving 4200 jobs, retaining $1.2 billion economic activity annually and avoiding increases in energy costs. The bill provides ZECs similar to those in New York – "a tradable credit that represents the environmental attributes of one megawatt hour of energy produced from a zero emission facility" such as the nuclear power plants which supply about 90% of the state’s zero-carbon electricity. The state legislature passed the bill in December 2016. It will provide up to $235 million annually to support the two plants for ten years. The state utilities will purchase ZECs from the nuclear generators and collect payments from ratepayers. The legislation sets the value of a ZEC to be $16.50/MWh based on the social cost of carbon.

A legal challenge to the Illinois ZEC programme failed, and in January 2019 a coalition of power generation companies took the appeal to the Supreme Court, where it was rejected.

In August 2019 Exelon said that its Braidwood, Byron and Dresden nuclear plants in the state were "financially challenged" and that the company was working with state lawmakers to ensure that they were included in any legislation that supports clean energy sources. In August 2020 Exelon said it planned to permanently close the Byron and Dresden nuclear power plants in September 2021 and November 2021, respectively. However, the premature retirement of the two plants was averted following the introduction of a new energy bill in September 2021 (see above).

Ohio

In February 2017 FirstEnergy announced that it was in dialogue with the Ohio state government to try to secure the future of its two nuclear plants in the state, Davis-Besse and Perry, a 894 MWe PWR and a 1256 MWe BWR respectively, owned by its subsidiary FirstEnergy Solutions *(Beaver Valley just over the border in Pennsylvania is excluded)*. The company had earlier announced its intention to withdraw from competitive generation markets by mid-2018, and in the fourth quarter of 2016 recorded a $9.2 billion impairment charge as a result.

In October 2017 a new bill was introduced into Ohio legislature aiming to establish the Zero Emissions Nuclear (ZEN) programme to support the state's two nuclear plants. The bill stated an initial ZEC price of $17/MWh. Each participating utility would be limited to purchasing one-third of its recorded 'total end user consumption' in MWh over the previous two calendar years.

FirstEnergy had 13,000 MWe of generating capacity operating in deregulated markets. It decided to relinquish all these assets by mid-2018, and withdraw from competitive generation altogether, maintaining only its generation assets in regulated markets. Due to competition from low-cost gas and subsidized wind power, the units were unlikely to be sellable if states failed to introduce legislation to provide zero emission credits. In March 2018, with the proposed Ohio bill stalled in a Senate committee, FirstEnergy filed a deactivation notice for its David-Besse and Perry plants, as well as its Beaver Valley plant in Pennsylvania. The deactivation notice set retirement dates of 2020 for Davis-Besse, and 2021 for Perry and Beaver Valley. FirstEnergy stated that it would continue to work with officials from the two states, and called on them to consider policy solutions to prevent early closure of the assets.

In May 2019 a bill (Ohio House Bill 6, HB6) creating the Clean Air Program passed Ohio's lower house. HB6 was approved by Ohio legislature and signed into law on 23 July 2019. It establishes credits for certified clean air resources, including nuclear plants, at $9/MWh. Under the bill, Ohio's electric distribution utilities collect a monthly charge capped at $0.85 from retail electric customers, and up to $2400 for large industrial plants, to fund payments to generators. Following the passing of the bill, FirstEnergy halted the deactivation orders for Davis-Besse and Perry. Several bills to repeal HB6 have since been introduced following the arrest in July 2020 of the Speaker of Ohio's House of Representatives and several others on charges of bribery to pass the legislation.

FirstEnergy Solutions filed for bankruptcy in March 2018 and in February 2020 it separated from its parent company when it emerged from bankruptcy protection as Energy Harbor.

Connecticut

In March 2017 Connecticut's Energy & Technology Committee approved a bill supporting the continued operation of Dominion's Millstone plant in that deregulated market. The bill "would expand the state's existing renewable electricity procurements to nuclear power by directing state regulators to solicit up to half of the facility's annual generation (*i.e.* 8.3 TWh) for five-year power purchase agreements." In October 2017, Connecticut's legislature passed the bill, supporting the continued operation of Millstone. After a 23:8 Senate vote, the lower house passed the bill 75:66. It made Dominion eligible to bid for long-term supply contracts for up to half of Millstone's output as a clean-energy resource, at higher prices, subject to the state Department of Energy and Environmental Protection and Public Utilities Regulatory Authority determining that this is in the public interest. The plant is the largest in New England and its viability has been eroded by cheap natural gas. Closure of the plant, which provides half of the state's power and almost all of its zero-carbon power, would jeopardize the state's ability to meet its long-term goals for reducing carbon emissions. In December 2018, the Public Utilities Regulatory Authority agreed that the Millstone nuclear plant was at risk, allowing it to take part in zero-emission energy auctions. In March 2019 the plant obtained a 10-year contract for 9 TWh per year with two utilities. The two units operating at Millstone – units 2&3 – are licensed to 2035 and 2045.

Kentucky

In March 2017 Kentucky voted to end its moratorium on nuclear power in the state.

Pennsylvania

In March 2017 Pennsylvania set up a bipartisan, bicameral nuclear energy caucus to secure the role of nuclear energy in the state, where it provides about 40% of the electricity and contributes $2.3 billion to the state GDP. There are several two-unit nuclear power plants in the state: Beaver Valley, Limerick, Peach Bottom and Susquehanna. Three Mile Island shut down in September 2019. Prior to its shutdown, Exelon said that the 890 MW Three Mile Island 1 was "economically challenged as a result of continued low wholesale power prices and the lack of federal or Pennsylvania energy policies that value zero-emissions nuclear energy."

A draft law updating the Pennsylvania Alternative Energy Portfolio Standards Act to include nuclear energy was introduced to the state's legislature in March 2019. Despite nuclear power's importance to the state, it is excluded from the AEPS programme. The Keep Powering Pennsylvania Act would offer subsidies to nuclear plants and was put forward as costing $500 million per year, significantly less than the cost if economically-challenged plants were to close. Plants applying to join the programme need to agree to operate for at least six years. The bill had not been passed by the time Exelon needed to decide on Three Mile Island's future.

New Jersey

In April 2018, New Jersey legislators passed bills establishing a ZEC programme. In April 2019 the New Jersey Board of Public Utilities (NJBPU) awarded ZECs to the Salem and Hope Creek nuclear power plants. The programme is to be funded by a 0.4 c/kWh tariff imposed on retail distribution customers. The bill requires plants to be licensed to operate until at least 2030, so excluded Exelon's Oyster Creek. Public Service Enterprise Group (PSEG), which operates the Hope Creek and Salem plants, had previously warned that closures were likely without intervention. The government expects that the two plants would receive about $200 million per year in revenue from ZEC sales to public utilities, apparently at around $10-11/MWh. The Oyster Creek plant (619 MWe net) closed in September 2018. Hope Creek 1 and Salem 1&2 are eligible to receive ZECs between April 2019 and May 2022. In April 2021 the NJBPU awarded a three-year extension, to 2025, for both plants.

In June 2017 MIT's Center for Energy and Environmental Policy Research published a new study that found that saving US nuclear "would come at a cost of $4-7/MWh on average in these markets, which is much lower than the cost of subsidizing wind power." The current production tax credit (PTC) level for renewables is $23/MWh.

Department of Energy rulemaking

Using its legislated authority for the first time since 1979, in September 2017 the Department of Energy (DOE) directed the Federal Energy Regulatory Commission (FERC) through a notice of proposed rulemaking (NOPR) to ensure that the country's "diverse mix of resources must include traditional base-load generation with onsite fuel storage that can withstand major fuel supply disruptions caused by natural and man-made disasters." The DOE said that FERC had so far “not done enough to address the crisis at hand” caused by the premature retirement of reliable plants. "Immediate action is necessary to ensure fair compensation in order to stop the imminent loss of generators with onsite fuel supplies, and thereby preserve the benefits of generation diversity and avoid the severe consequences that additional shutdowns would have on the electric grid," the DOE said in the NOPR. In particular, “the continued loss of base-load generation with onsite fuel supplies, such as coal and nuclear, must be stopped."

In January 2018 FERC halted the NOPR and called on operators of regional wholesale markets to "provide information as to whether the FERC and the markets need to take additional action on resilience of the bulk power system." This removed the built-in incentives for coal and nuclear plants outlined in the September NOPR which would have required independent system operators and regional transmission organizations "to ensure that certain reliability and resiliency attributes of electric generation resources are fully valued." In particular, it stated that eligible "fuel-secure generation units", which are frequently relied upon for grid reliability and resilience, must be able to fully recover their costs.

Transmission infrastructure

The USA has a patchwork of grids which are often barely interconnected. The Western Interconnection includes about 11 states plus British Columbia and Alberta. ERCOT (Electric Reliability Council of Texas) includes most of Texas, and Eastern Interconnection takes in the rest of the USA and Canada. There is very little grid capacity in the middle of the country. Exelon has temporarily curtailed off-peak output at one or more of its nuclear plants in Illinois numerous times for more than a year to late 2016 because of grid constraints. The company has previously said intermittent grid congestion has been occurring in the region around those plants because of transmission line outages for scheduled maintenance, large influxes of wind-generated power into the grid during off-peak hours, or a combination of those factors.

There is an evident need for major investment, and in August 2017 the DOE Staff Report to the Secretary on Electricity Markets and Reliability recommended that the Federal Energy Regulatory Commission (FERC) takes a leading role in ensuring effective grid connections to meet base-load demand more widely and reliably. See above section on Department of Energy rulemaking.

More information on the US grid situation is in the information paper on Electricity Transmission Grids.

Consolidation of ownership and management

The US nuclear power industry underwent significant consolidation in the early 2000s, driven largely by economies of scale, deregulation of electricity prices and the increasing attractiveness of nuclear power relative to fossil generation. As of the end of 1991, a total of 101 individual utilities had some (including minority) ownership interest in operable nuclear power plants. At the end of 1999, that number had dropped to 87, and the largest 12 of them owned 54% of the capacity. With deregulation of some states' electricity markets came a wave of mergers and acquisitions in 2000-1 and today the top 10 utilities account for more than 70% of total nuclear capacity. The consolidation has come about through mergers of utility companies as well as purchases of reactors by companies wishing to grow their nuclear capacity.

In respect to the number of operators of nuclear plants, this dropped from 45 in 1995 to about 30 in 2020, showing a substantial consolidation of expertise.

Mergers and consolidation of management

Most of the of nuclear generation capacity involved in consolidation announcements has been associated with corporate mergers, some of which failed due to regulatory opposition. Another means of consolidation has been via management contracts, and other means of management rationalisation for single-unit plants have also occurred. Details are in Appendix 2: Power Plant Purchases.

Purchase of reactors

In the 12 years from 1998, there were 20 reactor purchase deals involving 25 plants, usually in states where electricity pricing had been deregulated (see Nuclear Power in the USA Appendix 2: Power Plant Purchases). The plants acquired were often those with high production costs, offering the potential for increased margins if costs could be reduced. Of the 5900 MWe involved to mid-2000, half was associated with plants having 1998 production costs above 2.0 cents per kWh. Sellers tended to consider the higher-cost plants as potential liabilities and were willing to get rid of them for a fraction of their book value, whereas the larger utility buyers considered the plants to be potential assets, depending only on their ability to lower the production costs. In many cases, large power companies acquired plants from local utility companies and at the same time entered contracts to sell electricity back to the former owners. Entergy Corporation, for example, bought two reactors from New York Power Authority in 2000 and agreed to make the first 500 MWe of combined output available at 2.9 cents/kWh and the remainder at 3.2 or 3.6 cents/kWh.

Along with Exelon, Entergy is a prominent example of the consolidation that occurred. Originally based in Arkansas, Louisiana, Mississippi and eastern Texas, Entergy doubled its nuclear generation capacity over 1999 to 2007 with the acquisition of reactors in New York, Massachussets, Vermont and Michigan, as well as a contract to operate a nuclear plant in Nebraska. Other companies that have increased their nuclear capacity through plant purchases are FPL Group based in Florida (four units), Constellation Energy based in Maryland (three units, since merged with Exelon) and Dominion Resources based in Virginia (four units).

However, some older plants acquired from their original owners for their value as ‘cash cows’ are now unprofitable in deregulated markets and threatened with closure due to very low natural gas prices. In addition, onerous safety requirements following the Fukushima accident compound the economic challenges with already tight NRC regulations. See comments above (in the section on State initiatives zero-emission credits) regarding some Exelon and Entergy plants in deregulated markets.

Improved performance

So far about 165 uprates have been approved by the NRC, totalling over 7900 MWe. A further 260 MWe is prospective, under NRC review[i]

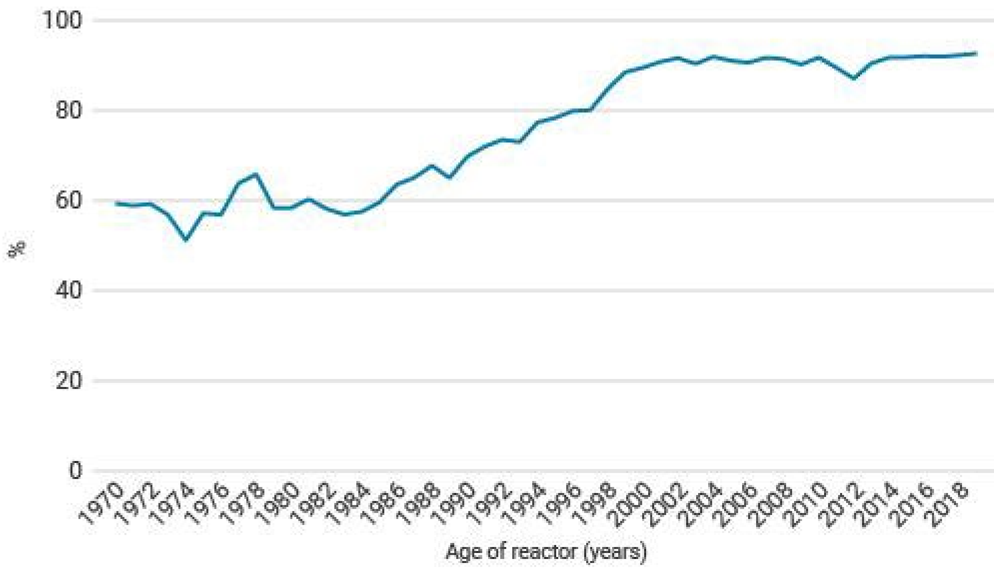
Florida Power & Light added 450 MWe in uprates to four reactors over 2011-13: 12% for St Lucie 1&2, and 15% for Turkey Point 3&4.

A significant achievement of the US nuclear power industry over the period 1980-2000 was the increase in operating efficiency with improved maintenance. This resulted in greatly increased capacity factors (output proportion of their nominal full-power capacity), which increased from about 60% in 1980 to about 90% in

2000 where it has remained since. A major component of this is the length of refuelling outages, which in 1990 averaged 107 days but dropped to 40 days by 2000. In 2017 the average refuelling outage was 35 days. The record is now 15 days. In addition, average thermal efficiency rose from 32.49% in 1980 to 33.40% in 1990 and 33.85% in 1999.

All this is reflected in increased output of 40% from 578 billion kWh in 1990 to 807 billion kWh in 2010, equivalent to 29 new 1000 MWe reactors, despite just a 5% increase in capacity.

Average capacity factor of US plants



Source: World Nuclear Association, IAEA PRIS

Reactors recently brought into operation

Watts Bar 2

While the focus is on new technology, TVA undertook a detailed feasibility study which led to its decision in 2007 to complete unit 2 of its Watts Bar nuclear power plant in Tennessee. The 1165 MWe (net) reactor was expected to start up in October 2012 and come online in 2013 at a cost of about $2.5 billion, but this schedule slipped substantially, with major budget overrun to $4.7 billion. Construction had been suspended in 1985 when 80% complete and (after parts were cannibalized to reduce that figure to 61%) resumed in October 2007 under a still-valid permit. The construction permit was extended to September 2016, and in October 2015 TVA received a 40-year operating licence from the NRC. Grid connection was early in June and commercial operation commenced in October 2016. Its twin, unit 1, started operation in 1996.

Completing Watts Bar 2 utilized an existing asset, thus saving time and cost relative to alternatives for new base-load capacity. It was expected to provide power at 4.4 ¢/kWh, 20-25% less than coal-fired or new nuclear alternatives and 43% less than natural gas. It is a regulated plant, with guaranteed cost recovery.

In 2014, before start-up, TVA ordered new steam generators for the unit and plans to change them over in 2022 at a cost of $160 million. The early 1980s ones are made of an alloy that is prone to stress corrosion cracking. Those in unit 1 were replaced after nine years of operation, and the vast majority of US PWRs have had replacements. In 2017 unit 2 was shut down for five months to replace a condenser that failed, and in 2020 it was running at 90% capacity due to wear in the four steam generators.

Notes & references

Notes

a. The first nuclear reactor in the world to produce electricity (albeit a trivial amount) was the small Experimental Breeder Reactor (EBR-1) in Idaho, which started up in December 1951. In 1953, President Eisenhower proposed his *Atoms for Peace* programme, which reoriented significant research effort towards electricity generation and set the course for civil nuclear energy development in the USA. The Mark 1 naval reactor of 1953 led to the US Atomic Energy Commission building the 60 MWe Shippingport demonstration PWR reactor in Pennsylvania, which started up in 1957 and operated until 1982. [Back]

b. Fort St. Vrain in Colorado was a 330 MWe high-temperature gas-cooled reactor (HTGR) operating 1976-89. The technology was developed from an earlier 40 MWe HTGR at Peach Bottom, Pennsylvania, which operated from 1967 to 1974. [Back]

c. The NRC had approved full design certification for the Westinghouse AP1000 in 2005 and issued a final rule certifying the design in January 2006. However, in May 2007, Westinghouse submitted an application to amend the AP1000 final design certification rule. [Back]

d. The ABWR design that has NRC certification is the GE Hitachi design, some aspects of which are proprietary to GE Hitachi. While the licence application for the first new ABWRs to be announced for the USA – at the South Texas Project (STP) – references the certified GE Hitachi design, Toshiba was selected as the main contractor to build the units. In November 2010, Toshiba submitted an application to renew the design, which includes revisions to bring the certified design in line with the STP units (see Note j below). [Back]

e. An asterisk (*) denotes reference COL for reactor type. EPC = Engineering, procurement and construction agreement. Merchant plants are without regulated cost recovery. 'Planned' status shows a higher level of commitment – such as an order for large forgings or an EPC contract – than 'Proposed' status. [Back]

f. Dominion's North Anna COL application referenced the ESBWR, but in March 2009 it issued a new request for proposals from reactor vendors and in May 2010 it selected the Mitsubishi US-APWR. Then in April 2013 it reverted to the ESBWR, and agreed on an EPC contract for it with GE Hitachi and Fluor.

The COL reviews of Entergy's applications for Grand Gulf and River Bend, along with the review of Exelon's application for the Victoria County site were suspended by the NRC, following the decisions by Entergy and Exelon to review their initial reactor design choice of the ESBWR. Exelon had initially proposed two ESBWR units for its Victoria County site but, early in 2009, switched to the ABWR design, to be built by GE Hitachi. Shortly afterwards, citing adverse economic conditions, Exelon withdrew its COL application. [Back]

g. The site chosen by the NuStart Energy Development consortium for the reference COL application for the AP1000 was originally TVA's Bellefonte. However, NuStart later decided to transfer the AP1000 reference COL application to Vogtle on the grounds that the Vogtle application had "specific near-term construction plans." In May 2009, NuStart announced that it was "consulting with the Nuclear Regulatory Commission and Department of Energy to develop a process for transferring the reference combined construction and operating licence application from TVA's Bellefonte nuclear site to Southern Nuclear's Vogtle Electric Generating Plant."[1] [Back]

h. A COL application for two proposed AP1000 units as units 3&4 at TVA's Bellefonte site was submitted to the Nuclear Regulatory Commission in October 2007. This COL application was originally the reference COL application for the AP1000 design but the reference application was transferred to Vogtle. The site also has two unfinished 1213 MWe PWRs (unit 1 being about 88% complete and unit 2 about 58% complete) and TVA has been considering all options for the site, including the completion of units 1&2. In May 2010 theTVA staff identified completion of unit 1 as the best option for the site, and in August 2011 the TVA Board decided to complete unit 1.[2] [Back]

i. AmerenUE announced in April 2009 that it was suspending its efforts to build a new unit and in June 2009 the company requested the Nuclear Regulatory Commission to suspend all review activities relating to the Callaway 2 COL application. However, in April 2012 Ameren Missouri set out to seek DOE support for the first of five Westinghouse SMR units at Callaway. In July 2015 Ameren withdrew its COL application. [Back]

j. Since the decision to go ahead with South Texas Project (STP) units 3&4 was first announced, there have been a number of developments. The combined construction and operating licence (COL) application was prepared by STP Nuclear Operating Company (STPNOC) together with GE Hitachi Nuclear Energy and Bechtel and submitted in September 2007.[3] Just before submittal of the COL application, NRG Energy and STPNOC signed a project services agreement with Toshiba to support the design, engineering, construction and procurement of the units. Fluor was then enrolled to support Toshiba[4]. In November 2010, Nuclear Innovation North America LLC (NINA, the nuclear development company jointly owned by NRG Energy and Toshiba) announced that it had awarded the engineering, procurement and construction (EPC) contract to a "restructured EPC consortium" of Toshiba's US subsidiary Toshiba America Nuclear Energy Corporation (TANE) and The Shaw Group[5] (later CB&I). Following CB&I's sale of its CB&I Stone & Webster subsidiary to Westinghouse (then owned by Toshiba), in May 2016 Toshiba and CB&I dissolved their 2010 partnership in relation to all ABWR plans, leaving TANE as the sole EPC contractor for the project.

In the meantime, the reactor technology moved from being based on the GE design certified by the US Nuclear Regulatory Commission in 1997. The design had to be renewed by 2012 and a renewal application by Toshiba was submitted in November 2010.[6] The renewal application included updates and revisions in accordance with the STP design. Hence, the STP reactors were considered to be Toshiba ABWRs, whereas the original intention was to use the 1997 certified design "with only a limited number of changes to enhance safety and construction schedules," with these changes incorporated into the COL application[7]. However, in 2016 Toshiba's application for design certification renewal was withdrawn. [Back]

k. The COL review by the NRC was due to be completed late in 2011, and the units were expected online in 2016 and 2017, but in late 2011 the NRC notified NINA that the corporation did not meet the foreign ownership requirements and would therefore be ineligible to receive a licence; however NINA subsequently filed revisions to its COL application and a "negation action plan" to address the issue. In April 2013 the NRC "determined that NINA and its wholly owned subsidiaries … continue to be under foreign ownership, control, or domination and do not meet the requirements … of the Atomic Energy Act or the requirements of (federal regulations)." The NRC decision was reviewed by the NRC Atomic Safety Licensing Board (ASLB), which ruled in April 2014 that the 10% Toshiba equity was no problem. NRC's Advisory Committee on Reactor Safeguards in April 2015 also supported issuing the COLs and the NRC issued a final safety evaluation report in September 2015. In February 2016 the NRC issued the COLs. [Back]

l. To the end of September 2010, the Nuclear Regulatory Commission (NRC) had approved 135 power uprates totalling 5810 MWe (not including capacity recapture uprates for provisional operating licence plants) and this had increased to 7921 MWe (164 uprates) as of October 2020. Information on power uprates is available on the NRC website. [Back]

References

1. NuStart Members Step Toward COL Completion, NuStart Update (1 May 2009) [Back]
2. TVA to Update Environmental Impacts Evaluation for Nuclear Unit at Bellefonte Site, TVA news release (7 August 2009). In April 2011 this was deferred further pending analysis of the Fukushima accident. [Back]
3. NRG Energy Submits Application for New 2,700 Megawatt Nuclear Plant in South Texas, NRG Energy news release (24 September 2007) [Back]
4. Contractors in flux for South Texas Project, World Nuclear News (20 August 2007) [Back]
5. NINA Announces Newly Developed EPC Consortium to Advance South Texas Project, Nuclear Innovation North America news release (29 November 2010) [Back]
6. Toshiba works on ABWR certification, World Nuclear News (4 November 2010) [Back]
7. NRG Forms Company to Develop Advanced Boiling Water Reactor Nuclear Power Projects in North America, NRG Energy news release (25 March 2008) [Back]
8. Final Environmental Impact Statement, Single Nuclear Unit at the Bellefonte Plant Site, Jackson County, AL, Federal Register, 53994 (30 August 2011) [Back]
9. Nuclear Costs in Context, Nuclear Energy Institute (October 2022) [Back]

General sources

Nuclear Energy Institute, Annual Briefing for the Financial Community, February 2014
Nuclear Regulatory Commission website

Appendices

Nuclear Power in the USA Appendix 1: US Operating Nuclear Reactors
Nuclear Power in the USA Appendix 2 Power Plant Purchases
Nuclear Power in the USA Appendix 3: COL Applications

Related information

USA: Nuclear Fuel Cycle
USA: Nuclear Power Policy

Exhibit 11

Electricity Generation

The United States leads the world in geothermal electricity-generating capacity—just over 4 gigawatts. That's enough to power the equivalent of about 3 million U.S. homes.

To generate power from geothermal systems, three elements are needed:

- **Heat**—Abundant heat found in rocks deep underground, varying by depth, geology, and geographic location.
- **Fluid**—Sufficient fluid to carry heat from the rocks to the earth's surface.
- **Permeability**—Small pathways that facilitate fluid movement through the hot rocks.

The presence of hot rocks, fluid, and permeability underground creates natural geothermal systems. Small underground pathways, such as fractures, conduct fluids through the hot rocks. In geothermal electricity generation, this fluid can be drawn as energy in the form of heat through wells to the earth's surface. Once it has reached the surface, this fluid is used to drive turbines that produce electricity.

Conventional hydrothermal resources naturally contain all three elements. Sometimes, though, these conditions do not exist naturally—for instance, the rocks are hot, but they lack permeability or sufficient fluid flow. Enhanced geothermal systems (EGS) use human-made reservoirs to create the proper conditions for electricity generation by injecting fluid into the hot rocks. This creates new fractures and opens existing ones to enhance the size and connectivity of fluid pathways. Once this engineered reservoir is created, fluid can be injected into the subsurface and then drawn up through a production well to generate electricity using the same processes as a conventional hydrothermal system.

The 2019 *GeoVision* analysis concluded that, with advancements in EGS, geothermal could power more than 40 million U.S. homes by 2050 and provide heating and cooling solutions nationwide. The 2023 Enhanced Geothermal Shot™ analysis found that the potential was even higher: technical advances would enable geothermal energy to power the equivalent of more than 65 million U.S. homes

GTO is also assessing opportunities to use sedimentary geothermal resources to produce electricity. Sedimentary rock formations commonly associated with oil and gas can also hold significant amounts of thermal energy. This creates opportunities to access additional geothermal resources and even to repurpose idle or unproductive oil and gas wells for geothermal electricity generation.

Learn More

Geothermal Basics

Fact Sheet: What is Geothermal Energy?

Enhanced Geothermal Systems

Hydrothermal Resources

Low Temperature & Coproduced Resources

Regional Partnerships for Geothermal Data

Geothermal Power Plants

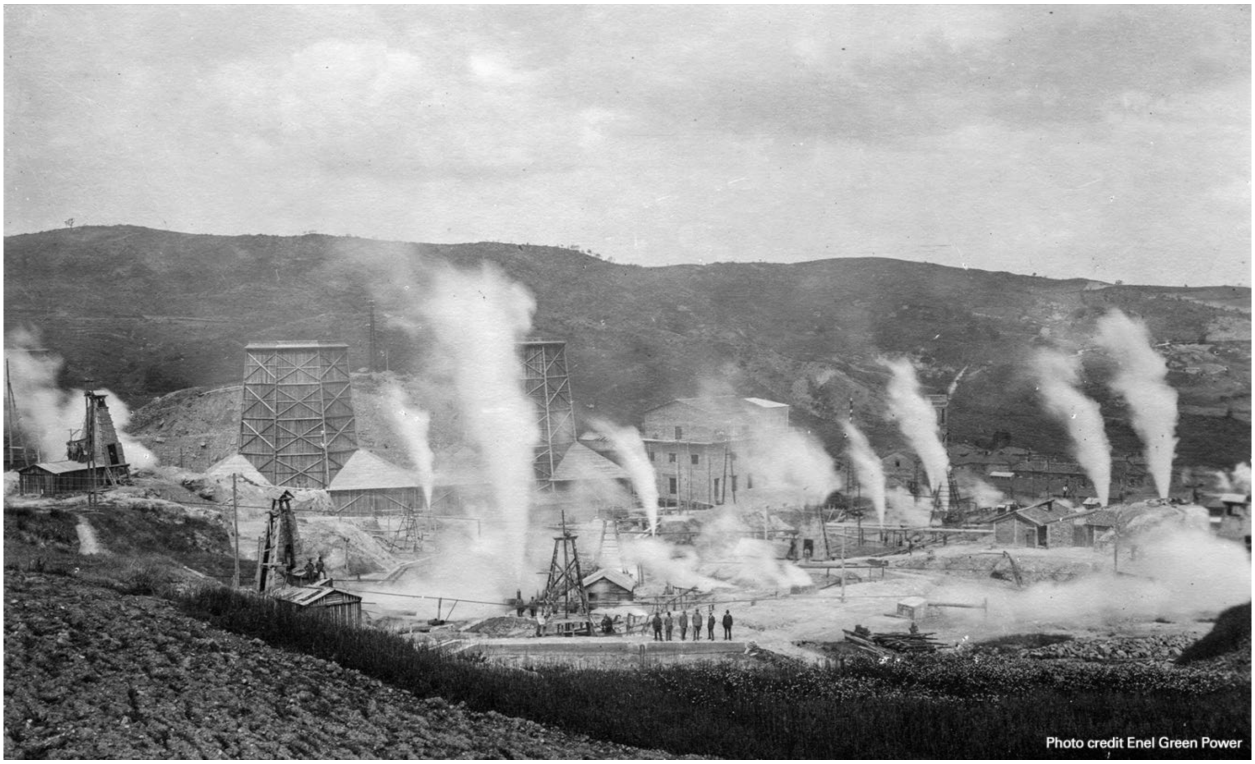
Geothermal power plants draw fluids from underground reservoirs to the surface to produce heated material. This steam or hot liquid then drives turbines that generate electricity before it is reinjected back into the reservoir.

There are three main types of geothermal power plant technologies: dry steam, flash steam, and binary cycle. The type of conversion is part of the power plant design and generally depends on the state of the subsurface fluid (steam or water) and its temperature.

See how we can generate renewable energy from hot water sources deep beneath Earth's surface. The video highlights the basic principles at work in geothermal energy production and illustrates three different ways Earth's heat can be converted into electricity.

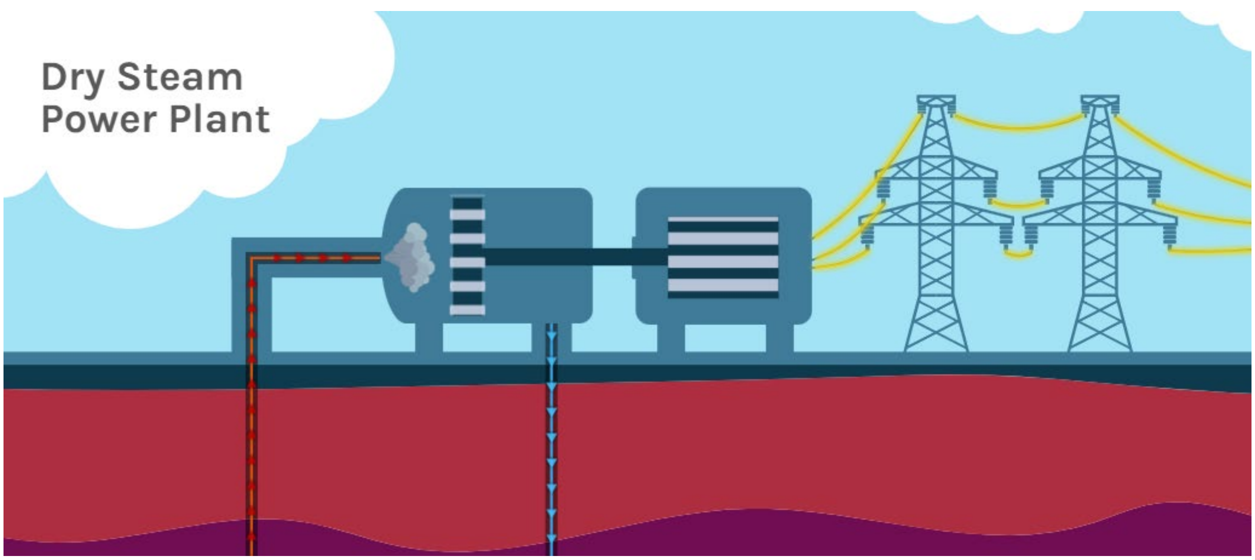
Dry Steam Power Plant

Dry steam plants use hydrothermal fluids that are already mostly steam, which is a relatively rare natural occurrence. The steam is drawn directly to a turbine, which drives a generator that produces electricity. After the steam condenses, it is frequently reinjected into the reservoir.



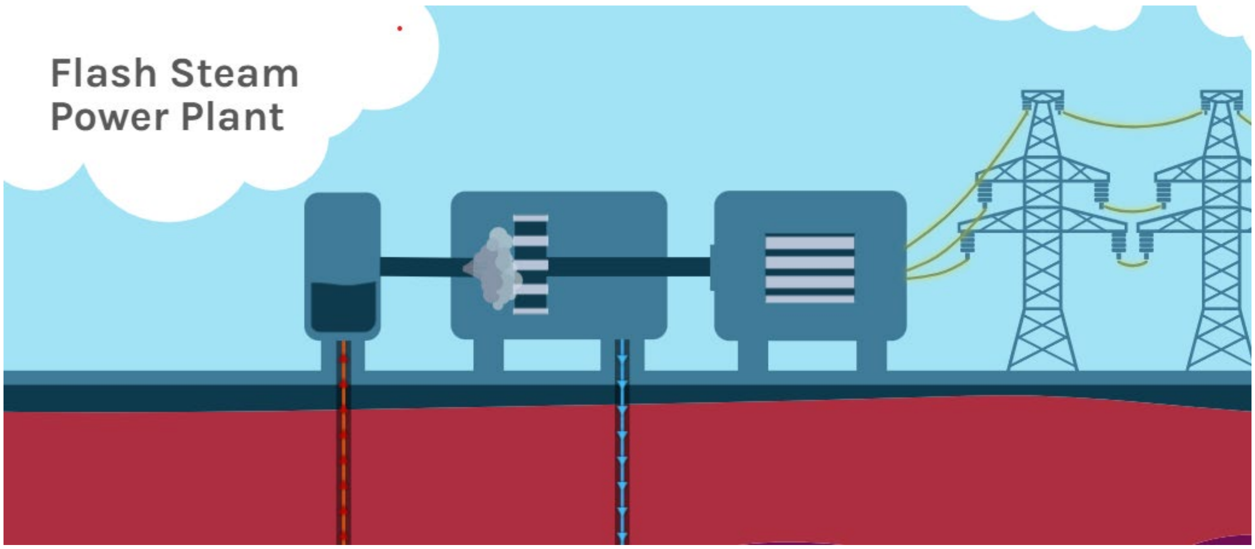
The Larderello geothermal power plant in Tuscany is the oldest dry steam power plant in the world.

Dry steam power plant systems are the oldest type of geothermal power plants, first used in Italy, in 1904. Steam technology is still relevant today and is currently in use in northern California at The Geysers, the world's largest single source of geothermal power.



Flash Steam Power Plant

Flash steam plants are a common type of geothermal power plant in operation today. Fluids at temperatures greater than 182°C/360°F, pumped from deep underground, travel under high pressures to a low-pressure tank at the earth's surface. The change in pressure causes some of the fluid to rapidly transform, or "flash," into vapor. The vapor then drives a turbine, which drives a generator. If any liquid remains in the low-pressure tank, it can be "flashed" again in a second tank to extract even more energy.



Binary-Cycle Power Plant

Binary-cycle geothermal power plants can use lower temperature geothermal resources, making them an important technology for deploying geothermal electricity production in more locations. Binary-cycle geothermal power plants differ from dry steam and flash steam systems in that the geothermal reservoir fluids never come into contact with the power plant's turbine units. Low-temperature (below 182°C/360°F) geothermal fluids pass through a heat exchanger with a secondary, or "binary," fluid. This binary fluid has a much lower boiling point than water, and the modest heat from the geothermal fluid causes it to flash to vapor, which then drives the turbines, spins the generators, and creates electricity.

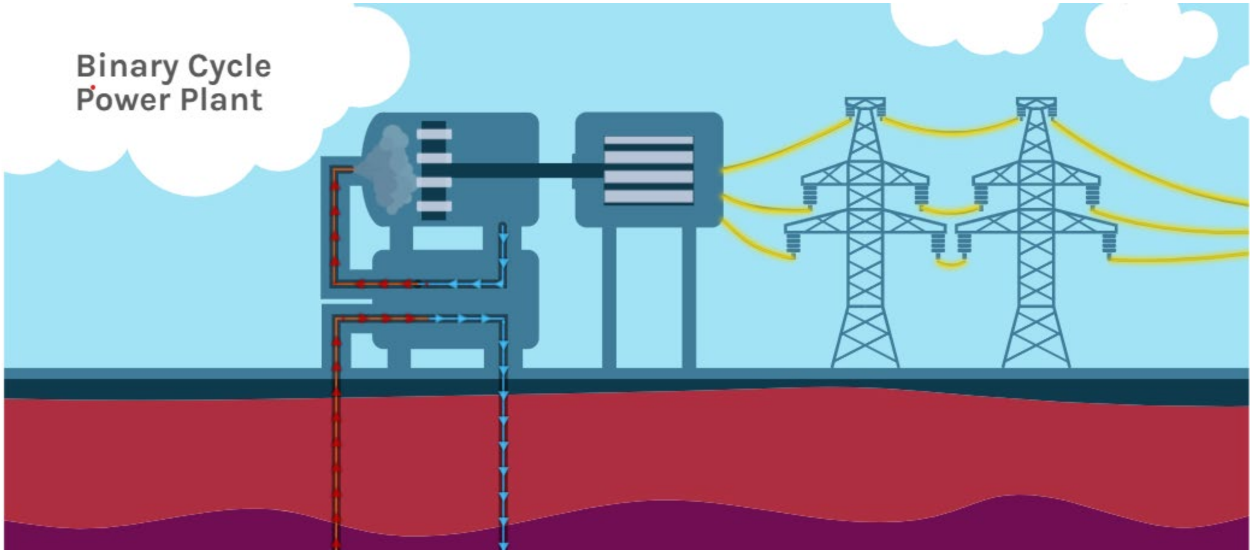

Binary Cycle
Power Plant

Exhibit 12

How the U.S. Power Grid Kept the Lights on in Summer 2024

Paul Denholm,[1] Victor Duraes de Faria,[1] and Jason Frost[2]

1 National Renewable Energy Laboratory
2 U.S. Department of Energy

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November 2024

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Paul Denholm,[1] Victor Duraes de Faria,[1] and Jason Frost[2]

1 National Renewable Energy Laboratory
2 U.S. Department of Energy

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List of Acronyms

BTM	behind-the-meter
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
GW	gigawatt
ISO	independent system operator
ISO-NE	ISO New England
MISO	Midcontinent Independent System Operator
MW	megawatt
NERC	North American Electric Reliability Corporation
NG	natural gas
NPCC	Northeast Power Coordinating Council
PV	photovoltaics
SERC	Southeast Regional Council
SPP	Southwest Power Pool
SRA	Summer Reliability Assessment
WECC	Western Electricity Coordinating Council

Table of Contents

List of Figures

1 Introduction

Maintaining the reliability of the bulk power system, which supplies and transmits electricity, is a critical priority of electric grid planners, operators, and regulators. The demand for electricity is increasing to power data centers, electrification of transportation and other end uses, and more[1]—all while the generation mix is rapidly evolving and fossil fuel plants are being retired. In many regions of the country, the demand for electricity often reaches its highest (peak) levels during summer afternoons when high temperatures drive increased use of air conditioning. Increasing frequency of extreme heat events are also adding to the challenge of serving summer peak demand. In addition, an evolving generation mix with increasing renewables and storage and retirements of older fossil-fueled generators are changing how grid operators maintain reliable electricity supply through these events.[2]

The North American Electric Reliability Corporation (NERC)[3] issues annual assessments and forecasts for the upcoming winter and summer seasons; these risk assessments estimate expected demand levels and the availability of electricity generation to meet that demand during periods identified as having the highest risk of electricity supply shortfall. In its 2024 Summer Reliability Assessment (SRA), NERC identified five regions—illustrated in Figure 1—as having an elevated risk of an outage in "above-normal" conditions.[4] This means these regions faced risks of energy shortfalls under some combination of electricity demand at the highest end of projected ranges and historically high generation outages. The rest of the United States[5] was expected to have "normal" levels of risk.

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[1] NERC Long-Term Reliability Assessment
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf
[2] This report focuses on the summer of 2024, but winter peaks can be higher in some regions and of growing concern in many other regions.
[3] NERC is an "international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid." https://www.nerc.com/AboutNERC/Pages/default.aspx
[4] NERC 2024 Summer Reliability Assessment
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf
[5] NERC's assessment does not consider Alaska or Hawaii, so this document only considers the conterminous (lower 48) states.

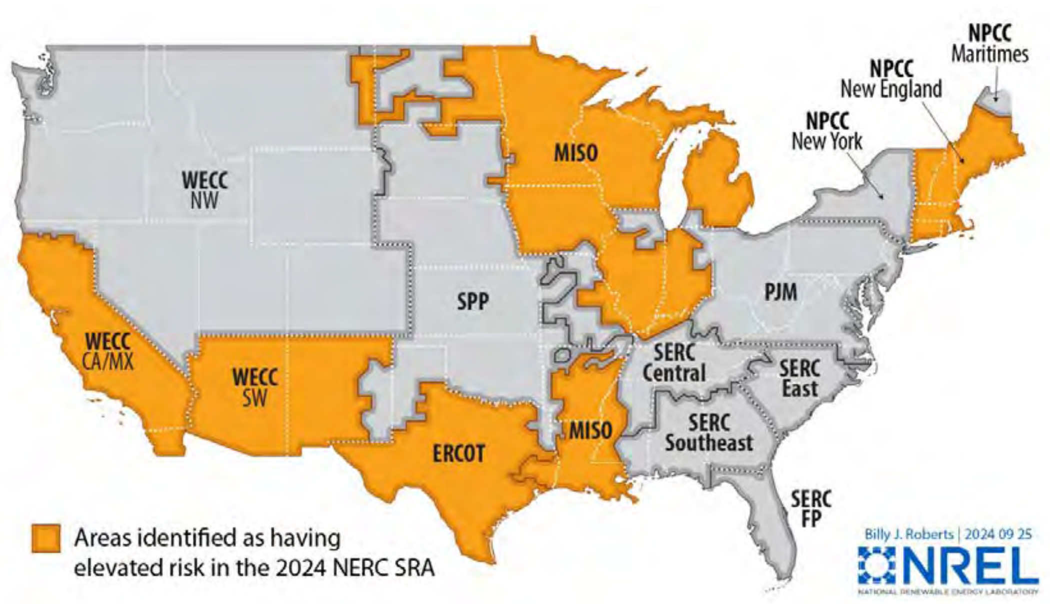

Figure 1. NERC risk assessment regions in the United States, highlighting five regions considered as having elevated risk in summer 2024

WECC = Western Electricity Coordinating Council; SPP = Southwest Power Pool; ERCOT = Electric Reliability Council of Texas; MISO = Midcontinent Independent System Operator; SERC = Southeast Regional Council; NPCC = Northeast Power Coordinating Council

Now that the 2024 summer season has ended and the data have been gathered, we can evaluate grid performance in these "elevated risk" areas of the country. Summertime temperatures in 2024 were above average,[6] driving high electricity demand. Several regions such as the Texas power grid came close to or hit record-high demand for electricity.[7]

Despite the high demand for electricity, there were no major outages caused by inadequate generation capacity. Although some consumers lost power because of localized events, the bulk power system—the network of generators and transmission lines—was able to supply sufficient electricity to keep the lights and air conditioners working.[8]

[6] The period of June–August was 2.5°F above average. NOAA "U.S. Climate Summary for August 2024." https://www.climate.gov/news-features/understanding-climate/us-climate-summary-august-2024

[7] ERCOT. October 10, 2024. "Board of Directors Meeting Item 7: Summer 2024 Operational and Market Review." https://www.ercot.com/files/docs/2024/10/03/7-summer-2024-operational-and-market-review.pdf.

[8] This discussion focuses on the bulk power system which consists of generators and the high-voltage transmission network. During summer 2024, there were no significant outages because of failures or insufficient capacity on the bulk power system. Local outages that occurred (and most outages in general) were because of failures on the distribution system, which is the set of lower-voltage wires and systems that deliver electricity from the bulk power system to homes and businesses. NREL "Explained: Reliability of the Current Power Grid" https://www.nrel.gov/docs/fy24osti/87297.pdf

This report briefly describes how various regions in the U.S. power grid kept the lights on in summer 2024. It also highlights notable trends in the evolving grid mix that are helping maintain summer peak reliability in places such as Texas—and how these trends could help maintain future summer reliability in regions throughout the United States.

2 How Did They Do It?

Grid operators used a mix of resources to keep the lights on this summer. Notably, along with existing thermal (fossil and nuclear) and hydropower generation resources, increasing solar and storage resources contributed significantly during peak demand periods in some regions. This report places special attention on Electric Reliability Council of Texas (ERCOT) because it is one of the fastest-growing regions in the country,[9] it experienced near-record peak demand in the summer of 2024, and it shows how rapidly increasing solar and storage deployments can impact summer peak operations. We also examine several other regions that NERC identified as having elevated risk and that vary in deployment of solar and storage resources.

2.1 ERCOT

Figure 2 shows the maximum daily electricity load[10] in ERCOT (black line) from June 1 through September 12, along with the maximum daily population-weighted average temperature[11] (blue line) over the same period. Prior to August 1, the demand peaks were generally below 80,000 megawatts (MW). However, an extended period of hot weather began in early August, with a maximum peak demand on August 20.

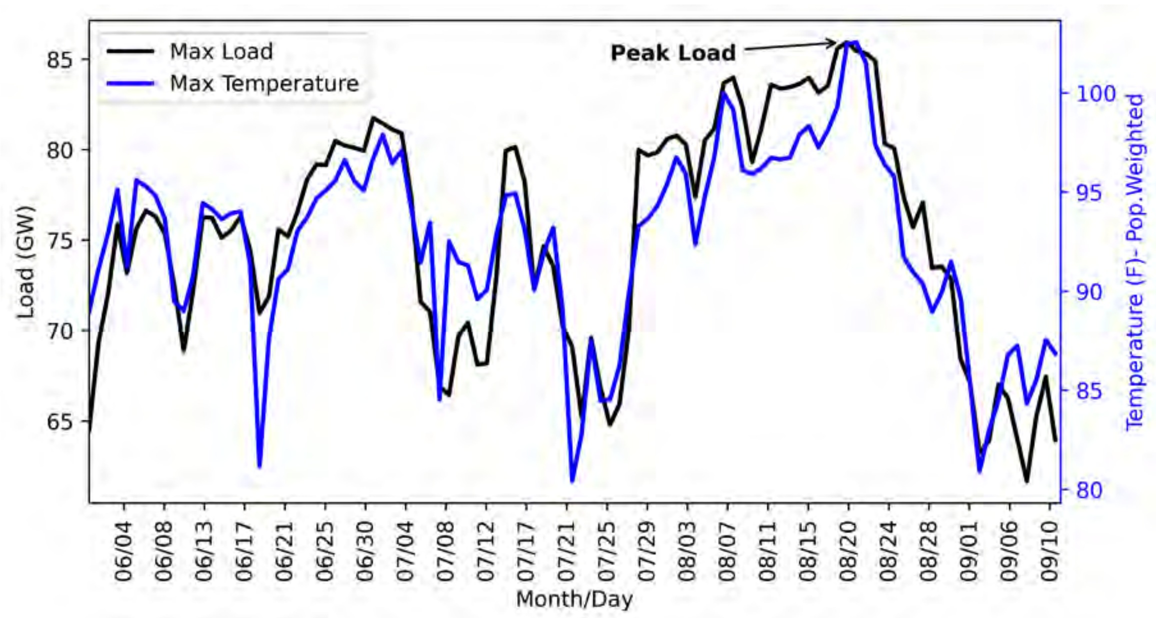

Figure 2. Maximum daily electricity demand (black) in ERCOT in summer 2024 was highest when peak temperatures (blue) averaged over 100°F in August

GW = gigawatts

[9] According to NERC's 2023 Electricity Supply and Demand report, ERCOT is projecting demand to grow 15% between 2022 (the last historical year included in the data) and 2026. This is faster than any other region, though load forecasts have continued to change since these data were released in December 2023.
[10] ERCOT load data from https://www.ercot.com/gridinfo/generation.
[11] We estimated the population-weighted average temperature across ERCOT using ZIP code level population from https://statics.teams.cdn.office.net/evergreen-assets/safelinks/1/atp-safelinks.html and temperature data from https://www.ncei.noaa.gov/pub/data/uscrn/products/subhourly01/.

Figure 3 zooms into August 20, the day with the peak demand. The average temperature across ERCOT hit about 102°F, with many regions experiencing higher temperatures. During the peak hour (4–5 p.m.), the average demand was 85,491 MW, with an instantaneous 5-minute peak of 85,931 MW. ERCOT was able to serve this load without generation-related shortfalls.[12]

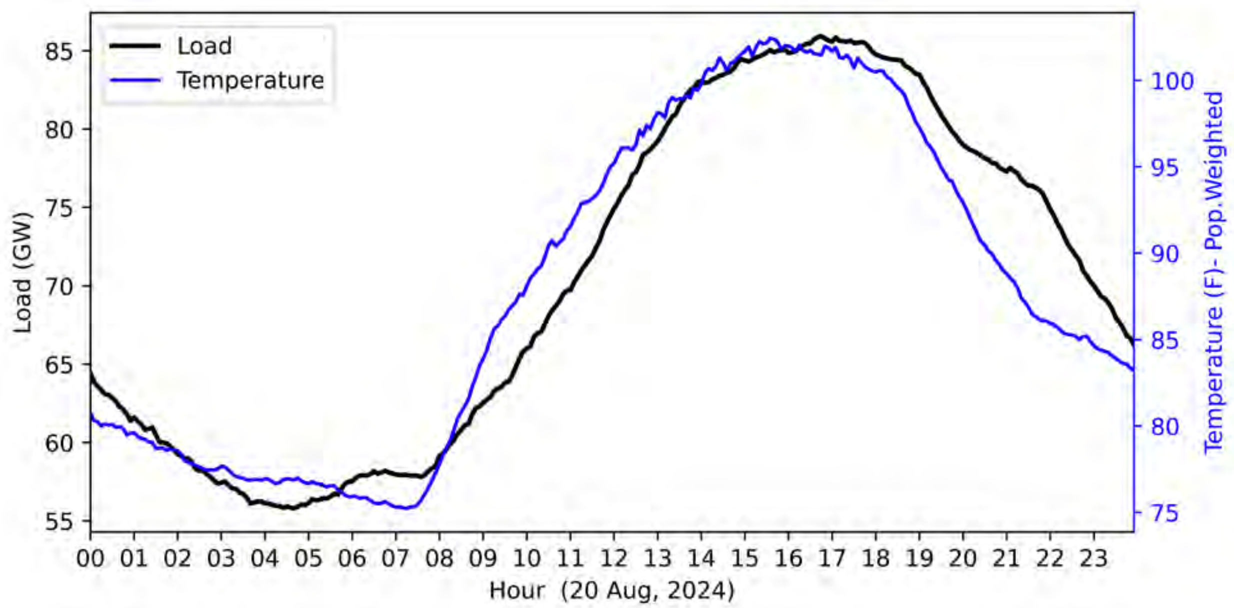

Figure 3. Demand profile and average temperature on August 20, 2024, showing near-record peak demand of more than 85 GW

Figure 4 illustrates the electricity generation by resource type that reliably met the electricity demand on August 20 in ERCOT.[13] Over this 24-hour period, about 66% of total generation was provided by fossil-fueled power plants, and these plants provided about 65% of generation during the peak hour. The remaining contribution was from low-carbon resources (renewables and nuclear). Utility-scale solar provided about 12% of the day's generation.[14] This solar generation had four impacts on the system's ability to serve demand, as illustrated in the figure and described next.

[12] As noted previously, there were local outages because of failures on the distribution system. Utility Dive "ERCOT successfully navigates heat wave, new peak demand record" https://www.utilitydive.com/news/ercot-successfully-navigates-heat-wave-new-peak-demand-record/725197/

[13] Data from ERCOT. https://www.ercot.com/gridinfo/generation

[14] Generation data from ERCOT does not include the contribution of behind the meter solar. The load profiles shown are therefore net of the BTM solar. In the 8-month period ending in August of 2024, BTM solar provided about 3.3 TWh, compared to 26.0 TWh from utility-scale systems in all of Texas (not just ERCOT).

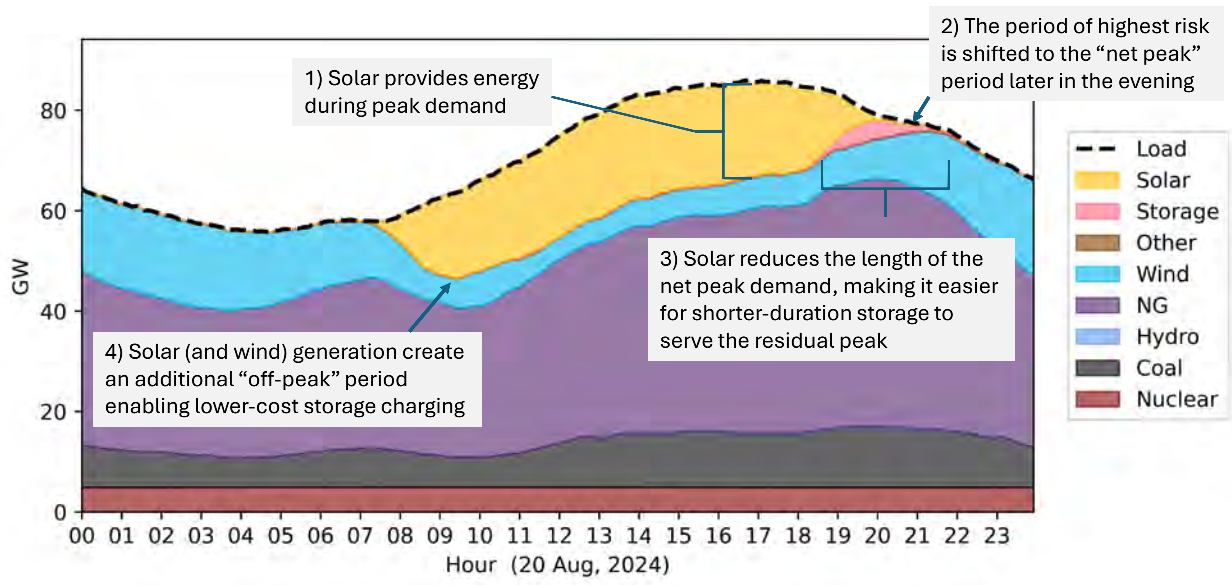

Figure 4. Generation resource mix on August 20, 2024, highlighting four impacts of solar on ERCOT's ability to achieve reliable operation

NG = natural gas

- **Solar significantly contributed to meeting peak demand.** During the hour of peak demand, solar generated at about 18 GW (generating at above 80% of its theoretical potential), providing about 21% of total generation. Solar's significant generation during the peak demand period reduced the risk of an outage during this period and therefore the amount of generation capacity needed from other sources to maintain reliability.
- **Solar shifted the period of highest risk to the evening.** Because of the significant solar generation during the period of highest demand, the period of highest risk was shifted to later in the evening. This shift is often characterized by examining the "net demand" defined as normal demand minus the contribution of certain renewable resources (typically solar or solar plus wind). The peak net demand (net peak) therefore represents the maximum instantaneous generation required from nonrenewable generators and storage. During the 5-minute period of the absolute peak (85.9 GW at 4:45 p.m.), solar generation reduced the net demand to 67.2 GW. This is substantially lower than the day's peak net demand of 78.6 GW, which occurred at 7:55 p.m., when solar output had dropped to near zero.[15]

  This shift in the net demand period increased the probability of wind being available during net load peaks.[16] Wind often has a significantly lower-than-average availability

[15] Historically, NERC forecasts the hour of peak demand (which typically occurs between 3 and 5 p.m.) to estimate system risk. However, in some systems with significant solar (such as ERCOT and California), NERC now forecasts the net peak (removing the contribution of solar) as the period of highest risk. NERC 2024 Summer Reliability Assessment

[16] Harrison-Atlas et al. "Temporal complementarity and value of wind-PV hybrid systems across the United States" https://doi.org/10.1016/j.renene.2022.10.060

during summer afternoon peaks.[17] It provided only about 6 GW to the ERCOT grid during the period of absolute peak, despite an installed capacity of about 38.7 GW. Wind generally has higher availability in the evening, as shown previously in Figure 4 and later in Figure 9.

- **Storage provided a meaningful contribution to the net peak demand, enabled by solar generation.** Although solar by itself did not reduce the net peak demand past sunset, it changed the shape of the net peak period by making it shorter. Figure 5 shows this by comparing the total load (black line) and the net load after the contribution of solar was removed (dotted black line). This allows shorter-duration (and less-costly) storage to provide reliable capacity. Storage in ERCOT provided as much as 3.9 GW (about 4%–5% of total generation) during this period.

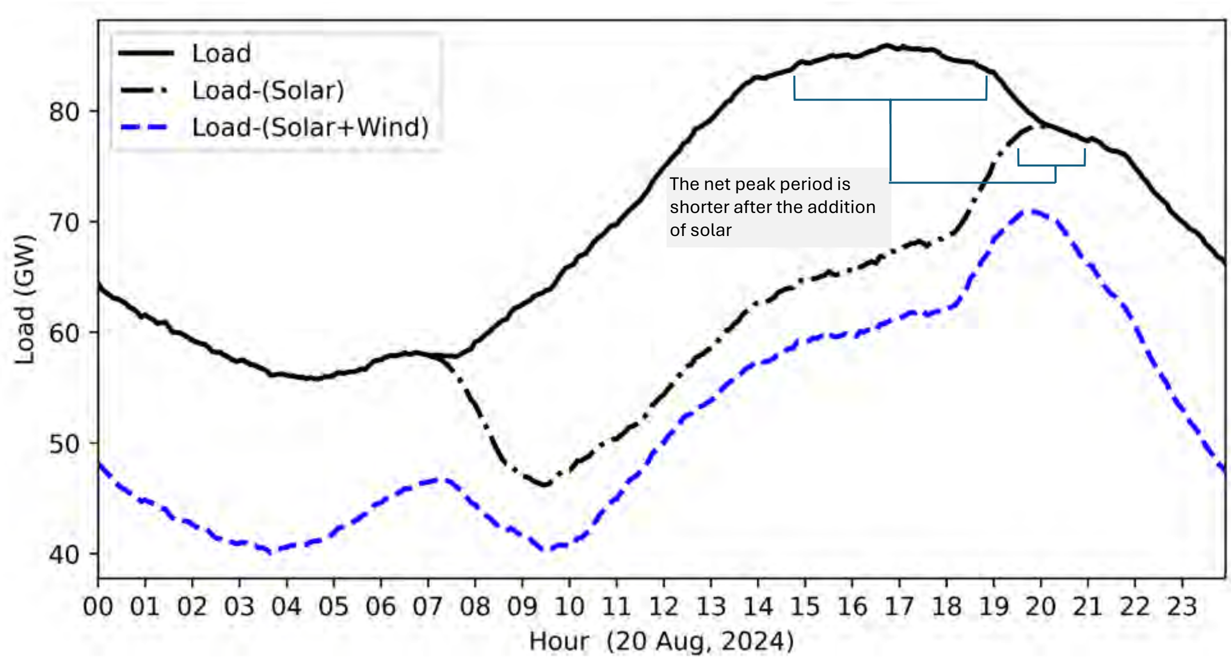

Figure 5. Solar reduces the length of the net peak demand period, reducing the duration of storage required while also increasing the amount of "off-peak" energy available for storage charging.

- **Solar (and wind) increased the availability of off-peak energy for storage charging.** Most recently deployed batteries have relatively short duration (4 hours or less) and generally must recharge every day to provide reliable capacity during extended periods of hot weather. During periods of high temperatures, nighttime demand often stays relatively high. Although there is plenty of spare thermal capacity (coal and gas) for recharging, storage may be forced to purchase power at prices set by relatively high-priced generators. However, solar generation in the late morning and wind overnight reduced the net demand, creating longer or "deeper" off-peak periods as shown in

[17] NERC 2024 Summer Reliability Assessment

Figure 5 (with the net load including wind, shown in blue)—which allowed lower-cost charging from existing thermal units.[18]

Overall, during the peak summer period in 2024, ERCOT met demand with a combination of legacy resources (natural gas and other thermal resources) and the more recent additions of solar and energy storage. The contribution of solar and storage will continue to grow as more of these resources are deployed. As of September 2024, utilities and developers in Texas have added (cumulatively) about 19 GW of solar and 5 GW of batteries, mainly in the last few years, as shown in the solid bars in Figure 6.[19] That is still much less than the 67 GW of natural gas and 14 GW of coal, with installations that date back to before 1960.

Figure 6 also shows estimates of future capacity additions, including those that have been completed as of August 2024, or are under construction or in various stages of approval. The continued growth of both solar and storage is expected to supply an increasing fraction of demand on hot summer afternoons and evenings.[20]

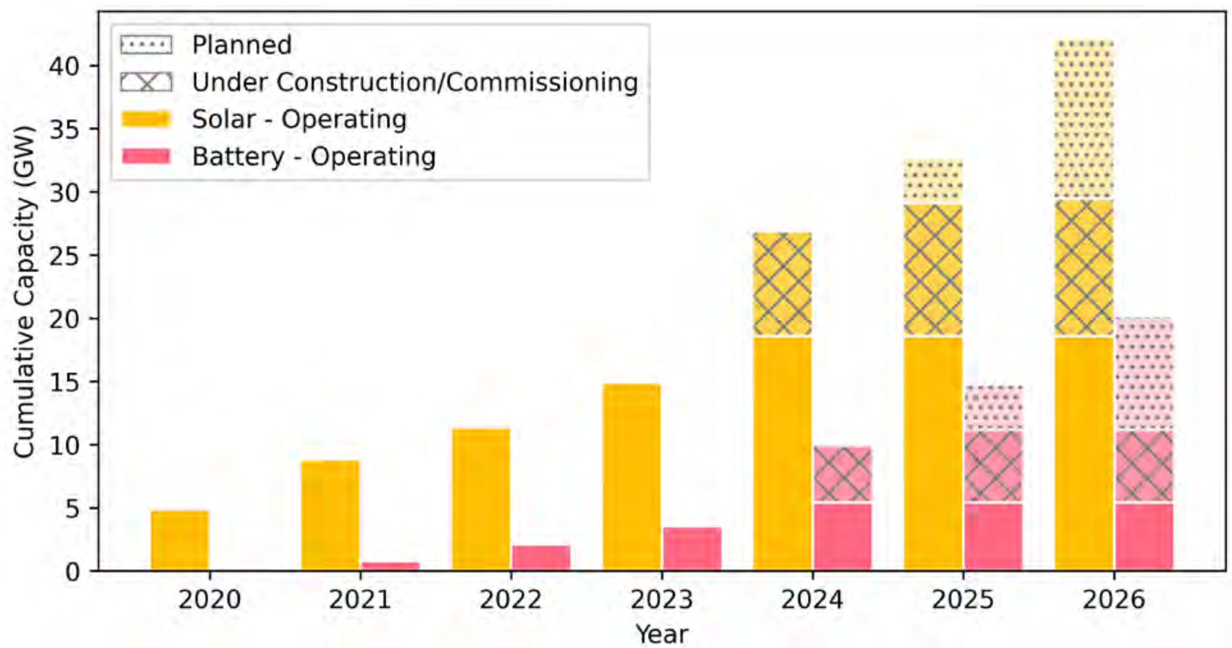

Figure 6. Cumulative solar and storage deployment in ERCOT shows significant growth since 2020 with further growth expected

Values for 2024 are as of August from EIA 860m

[18] The overall change in shape of the net load that results from significant solar deployment is characterized by a low net demand in the middle of the day, and a rapid increase in net demand towards sunset. The resulting shape is sometimes referred to as the duck curve. https://www.nrel.gov/docs/fy16osti/65023.pdf
[19] EIA Form 860m data https://www.eia.gov/electricity/data/eia860m/
[20] NREL Standard Scenarios. https://www.nrel.gov/analysis/standard-scenarios.html

2.2 Other Regions

In other parts of the country, demand on peak days was met by different mixes of legacy thermal, hydropower, renewable, and storage resources, often supplemented by imports from other regions via transmission. However, many regions are now seeing significant contributions from solar.

Although some regions like ERCOT only report utility-scale solar generation, contributions from solar include both utility-scale and behind-the-meter (BTM) systems. The actual contribution from BTM solar toward meeting peak demand can be difficult to determine because it is often not reported. However, some regions report estimated BTM solar generation, and the significant role of BTM solar can be observed in the ISO New England (ISO-NE) region—which corresponds to NERC's NPCC-New England region.[21] Figure 7 shows the generation mix on the peak day (July 16), highlighting the contributions from both BTM and utility-scale solar. Notably, most of New England's solar is in the form of BTM, which was able to provide about 12% of the system generation during the peak demand hour, with utility-scale solar contributing an additional 2%.

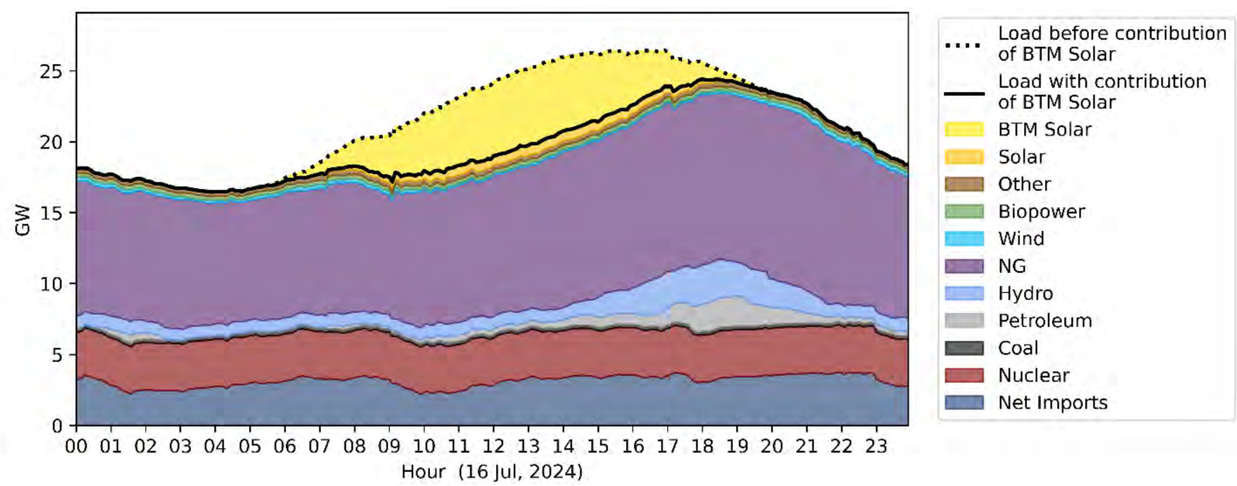

Figure 7. Generation resource mix on July 16, 2024, in the ISO-NE region, showing the large contribution of behind-the-meter solar

The figure also shows the significant role of dispatchable hydropower as well as electricity imports from other regions. New England is also one of the few regions of the country that relies on oil-fired peaking units. These units are operated relatively infrequently because they have high fuel costs and are among the most expensive to operate.

Although ERCOT has primarily utility-scale solar and New England has mostly BTM solar, California has large quantities of both. This solar capacity provided a significant benefit during California's peak demand day on September 5.

[21] https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type

Figure 8 shows the generation mix on the peak day for the California ISO (CAISO) area, which corresponds to about 80%[22] of California's electricity demand.[23] Only utility-scale solar is shown, but CAISO reported more than 15.7 GW of BTM solar in its system in addition to the more than 18.5 GW of utility-scale solar in 2024.[24] The presence of BTM solar is reflected in the load shape, which would include more load in the middle of the day in the absence of BTM solar, and shifts the load peak to later in the day, even before the contribution of utility-scale solar.

During the peak hour, about 24% of CAISO's demand was met by utility-scale solar.[25] The resulting net load after the contribution of solar (lower dashed line) creates a steep but short net peak that can be cost-effectively met with energy storage, with its ability to rapidly increase output.[26] During the hour of peak net demand, storage provided about 13% of total generation, with the remainder provided by natural gas, hydropower, imports, and other resources including wind.[27] Figure 8 also shows the significant storage charging occurring in the early morning and during the late morning off-peak period. This off-peak period is a result of substantial solar generation occurring before the afternoon increase in demand as previously shown in Figure 4 and Figure 5.

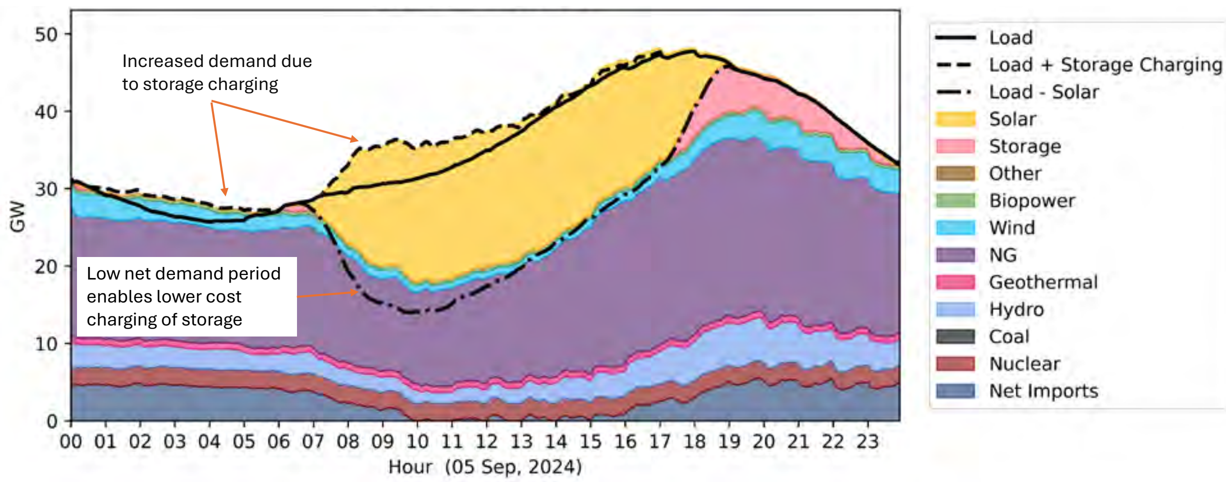

Figure 8. Generation resource mix on September 5, 2024, in the CAISO region, showing the large contribution of solar and storage toward meeting peak demand

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[22] CAISO Key Statistics September 2024 https://www.caiso.com/documents/key-statistics-sep-2024.pdf

[23] Data from https://www.caiso.com/todays-outlook/supply. Although NERC's SRA evaluated the slightly larger WECC-CA/MX region, complete data for that region is not publicly available.

[24] https://www.caiso.com/documents/april-8-solar-eclipse-technical-bulletin-march-11-2024.pdf

[25] Because of the shift in peak load caused by BTM solar, utility-scale solar output has already begun to drop. In the hour of peak demand, utility-scale solar is generating at about 38% of rated capacity and dropping rapidly.

[26] NREL Storage Futures Study Key Learnings for the Coming Decades https://www.nrel.gov/docs/fy22osti/81779.pdf

[27] In addition to having more storage capacity (by power) than ERCOT, California's storage tends to have more energy (duration) per unit of power capacity. For a discussion of drivers behind regional duration, see https://www.nrel.gov/docs/fy23osti/85878.pdf.

In other parts of the country, such as those served by MISO, there is relatively less installed solar and storage capacity, so the solar and storage share of peak day generation was significantly lower than in regions such as Texas, New England, and California. Peak demand in these other areas was reliably met largely with thermal generators and with smaller contributions from hydropower, solar, and wind. Figure 9 provides an example of the generation mix in MISO on the peak demand day on August 26.[28] Compared to the other regions examined above, MISO remains more dependent on natural gas and coal generation. Regions like MISO have significant opportunity to deploy more solar and storage to help meet summer peak demand in the future.[29]

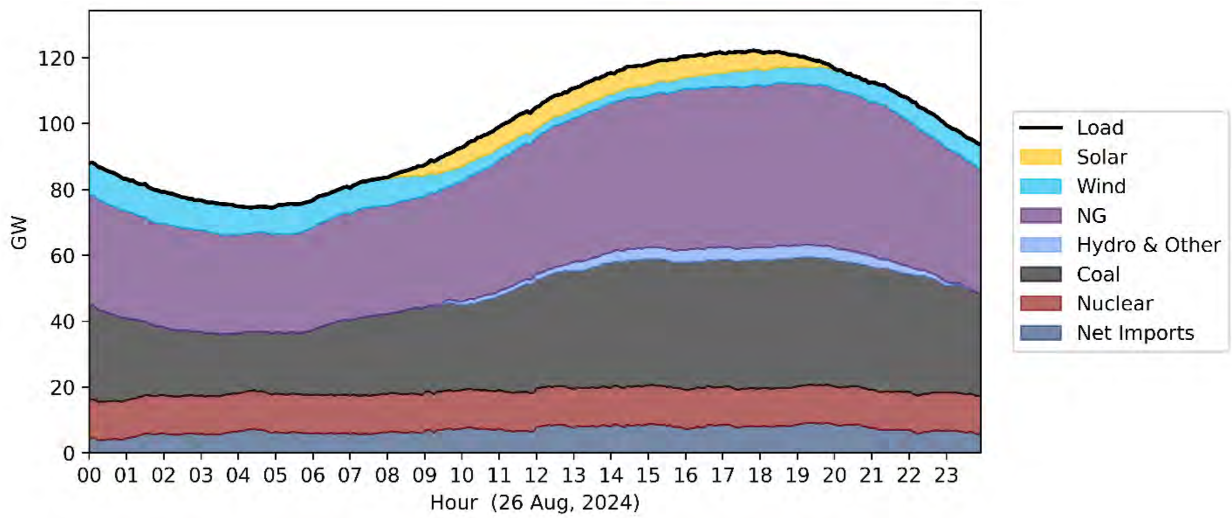

Figure 9. Generation resource mix on August 26, 2024, in the MISO region, showing limited contribution from solar and other low-carbon resources

[28] https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-report-archives/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc
[29] Frazier et al. Assessing the potential of battery storage as a peaking capacity resource in the United States. https://www.sciencedirect.com/science/article/pii/S0306261920308977

3 Maintaining Reliability During Future Summer Peaks

Both the supply and demand of electricity are changing quickly. Demand is growing to power data centers and an expanding digital economy, a U.S. manufacturing renaissance, and the electrification of transportation and other end uses[30]—all while the generation mix is rapidly evolving. Historically, the grid has primarily relied on thermal and hydropower resources to keep the lights on during summer peaks. But increasingly rapid deployment of grid-scale solar and storage are enabling these technologies to play a larger role.[31]

Summer 2024 demonstrated the combined ability of solar and storage to provide valuable capacity during summer peaks in diverse regions across the country, including Texas, California, and New England. Greater solar output increased the availability of clean generation during hot summer afternoons, shortened net peaks, and shifted those peaks to the evenings. As the sun set, grid-scale battery storage played a crucial role by discharging stored energy that helped maintain grid reliability until cooler temperatures reduce loads overnight.

The performance of the Texas and California power grids in summer 2024 showed that solar and storage can work together to help power the grid through peak summer demand days. Storage with relatively short duration (2–6 hours) can provide a significant portion of summer peak demand in all regions of the United States.[32]

3.1 Projected Solar and Storage Growth

In the coming years, even more solar and storage is planned to be connected to the grid. Figure 10 shows projections from the Energy Information Administration (EIA) with estimates of more than 140 GW of grid-scale solar installed in the United States by the end of 2025, compared to 109 GW as of August 2024. [33] These data also project grid-scale battery storage will grow from 22 GW to 38 GW over the same time frame. There is also a large amount of solar and storage resources waiting in interconnection queues planned for installation beyond 2025. Based on these trends, solar and storage will likely have a growing role in keeping the lights and air conditioning working on the hottest summer days in more regions across the country.[34]

[30] Wood Mackenzie projects data centers will add 25 GW of new demand, manufacturing will add 15 GW, electrification will add 7 GW, by 2029. US utilities to face significant challenge as power demand surges for the first time in decades | Wood Mackenzie. Grid Strategies also identifies data centers, large industrial loads, and electrification as key drivers of growing demand: National-Load-Growth-Report-2023.pdf (gridstrategiesllc.com).

[31] Denholm, P. *Explained: Maintaining a Reliable Future Grid with More Wind and Solar*. National Renewable Energy Laboratory. NREL/FS-6A40-8729 https://www.nrel.gov/docs/fy24osti/87298.pdf

[32] Blair, N., et al. *Storage Futures Study: Key Learnings for the Coming Decades*: National Renewable Energy Laboratory. NREL/TP-7A40-81779

[33] Data includes Alaska and Hawaii. EIA 860m https://www.eia.gov/electricity/data/eia860m/

[34]https://emp.lbl.gov/queues

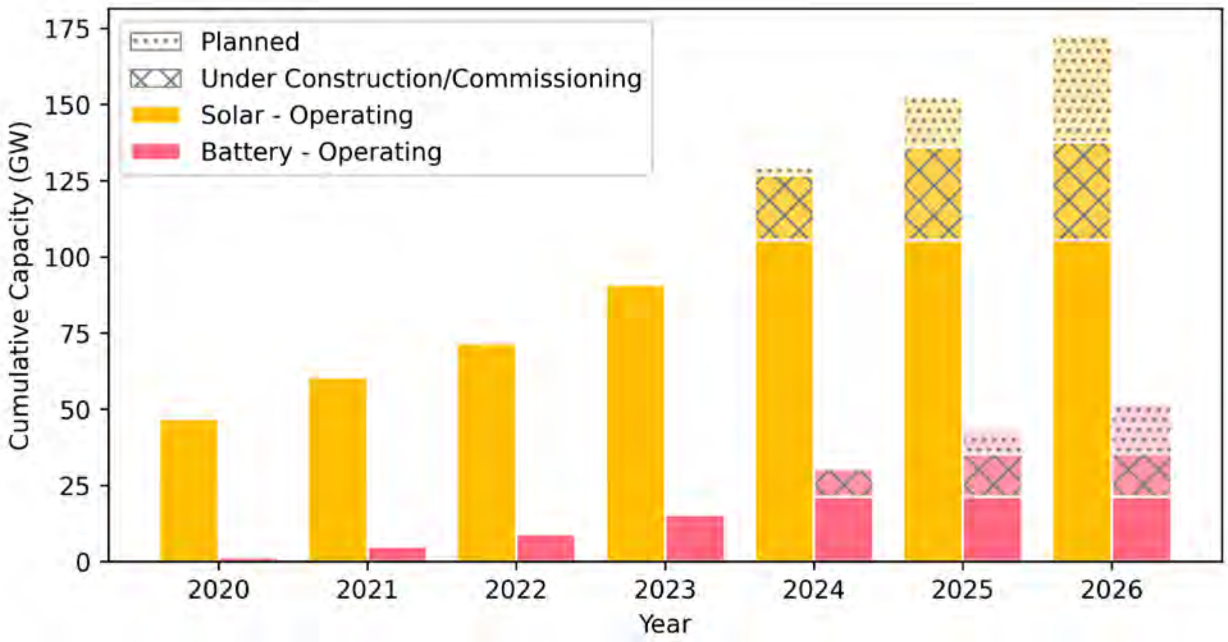

Figure 10. National projections from the EIA show substantial near-term growth of both solar and battery storage is expected

Values for 2024 are as of August from EIA 860m

3.2 Evolving Challenges and Opportunities

Leveraging the capabilities of diverse generation resources can improve reliability. Each resource type can serve specific needs, enabling the combined portfolio to provide consistent reliable power during peak hours. The power grid will never rely solely on solar and storage to meet all system needs. As load changes, so will the resource mix. In the near term, thermal resources will continue to play a critical role in meeting demand, including during system peaks, though their utilization is expected to decline as solar, storage, and wind resources grow.

The integration of more diverse generation resources involves changing the processes used to ensure sufficient generation capacity is available to serve demand at all times.[35] Historically, planners have forecast peak loads and maintained nameplate generation capacity equal to that peak load plus a reserve margin to cover outages and forecast uncertainty. As more renewable and storage resources connect to the bulk power system, different resources provide different combinations of services or value to the grid. This can cause the hours during which the grid is most stressed to shift to later in the day during the summer, as has happened with growing solar deployment in Texas and California, as well as to periods of low solar output in the winter. In the future, it will be increasingly important for grid planners and operators to consider other possible periods of grid stress in addition to summer peaks.

[35] ESIG Redefining Resource Adequacy for Modern Power Systems https://www.esig.energy/resource-adequacy-for-modern-power-systems/

In this context, more sophisticated probabilistic analysis that evaluates contributions of all resources during times of greatest system stress is needed to ensure the resource mix can serve total demand in both summer and winter as load grows, demand patterns shift, and the role of renewable generation increases.[36] Many grid operators have recently implemented or are currently implementing such approaches.[37] Careful and rigorous planning and additional improvements to planning frameworks is important to ensure continued reliable system operation.

Alongside solar, storage, and wind, other clean resources can bring a variety of benefits to the power system in future summers. These resources include supply-side technologies such as nuclear, geothermal, and long-duration storage that can provide power during periods of greatest system need. They also include transmission infrastructure to bring power to where it is needed most, connect new resources to loads, and improve power system resilience to extreme weather. Innovative demand-side technologies can play an important role, too, enabling consumers to implement grid-edge solutions that reduce peak demands and serve as virtual power plants while reducing customer and system costs.[38] The Bipartisan Infrastructure Law[39] and Inflation Reduction Act[40] are investing tens of billions of dollars into demonstrating and deploying this suite of new technologies. At the same time, the Federal Energy Regulatory Commission is reforming transmission planning and interconnection processes to facilitate the market entry of new resources.[41,42] With continued rigorous planning, these new resources can build on the value that thermal plants, hydropower, solar and storage, and wind are already providing to keep the power system operating smoothly during both summer peaks and other future periods of grid stress.

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[36] DOE. The Future of Resource Adequacy. 2024 The Future of Resource Adequacy Report.pdf (energy.gov)
[37] PJM adopted a marginal ELCC capacity accreditation framework for its 2025-2026 capacity auction: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false. ISO New England is developing a Marginal Reliability Impact accreditation framework that it plans to implement beginning June 1, 2028: https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.
[38] U.S. Department of Energy (DOE). The Future of Resource Adequacy. 2024 The Future of Resource Adequacy Report.pdf (energy.gov)
[39] Infrastructure Investment and Jobs Act. https://www.congress.gov/bill/117th-congress/house-bill/3684/text.
[40] Inflation Reduction Act. https://www.congress.gov/bill/117th-congress/house-bill/5376.
[41] Federal Energy Regulatory Commission. Order 2023. https://www.ferc.gov/media/e-1-order-2023-rm22-14-000.
[42] Federal Energy Regulatory Commission. Order 1920. https://www.ferc.gov/media/e1-rm21-17-000.

Exhibit 13

Active Power Controls from Wind Power: Bridging the Gaps

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List of Acronyms

AC	alternating current
ACE	area control error
AGC	automatic generation control
APC	active power control
BA	balancing area
CAISO	California ISO
CART3	3-Bladed Controls Advanced Research Turbine
DC	direct current
DDC	dynamic droop curve
DEL	damage equivalent load
DLL	dynamic-link library
EI	Eastern Interconnection
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FSC	filtered split controller
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IFRO	Interconnection Frequency Response Obligation
ISO	independent system operator
LMP	locational marginal price
MAPS	Multi-Area Production Simulation
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWTC	National Wind Technology Center
NYISO	New York ISO
PFC	primary frequency control
PI	proportional-integral
PSLF	Positive Sequence Load Flow
ROCOF	rate of change of frequency
RTO	regional transmission organization

SCADA	supervisory control and data acquisition
SDC	static droop curve
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
TEPPC	Transmission Expansion Planning Policy Committee
TSR	tip-speed ratio
UFLS	under-frequency load shedding
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WTG	wind turbine generator
WWSIS-1	Western Wind and Solar Integration Study Phase 1

Executive Summary

Wind energy has had one of the most substantial growths of any source of power generation. In many areas throughout the world, wind power is supplying up to 20% of total energy demand, and in some instances it provides more than 50% of the power in certain regions. Wind power falls under the category of variable generation, as its maximum available power varies over time (variability), and it cannot be predicted with perfect accuracy (uncertainty). Wind power, particularly variable-speed wind power, which is the majority of all wind plant capacity of the world, is also different from conventional thermal and hydropower generating technologies, as it is not synchronized to the electrical frequency of the power grid and is generally unresponsive to system frequency.

These three characteristics—variability, uncertainty, and asynchronism—can cause challenges for maintaining a reliable and secure power system. Many studies have been performed to better understand these system impacts. Utilities, balancing area (BA) authorities, regional reliability organizations, and independent system operators (ISOs) are also developing improved strategies to better integrate wind and other variable generation. Demand response, energy storage, and improved wind power forecasting techniques have often been described as potential mitigation strategies. The focus of this report is a mitigation strategy that is not often discussed and is in some ways counterintuitive: the use of wind power to support power system reliability by providing active power control (APC) at fast timescales. APC is the adjustment of a resource's active power in various response timeframes to assist in balancing the generation and load, thereby improving power system reliability.

The National Renewable Energy Laboratory (NREL), along with partners from the Electric Power Research Institute and University of Colorado and collaboration from a large international industry stakeholder group, embarked on a comprehensive study to understand the ways in which wind power technology can assist the power system by providing control of its active power output being injected onto the grid. The study includes a number of different power system simulations, control simulations, and actual field tests using turbines at NREL's National Wind Technology Center (NWTC). The study sought to understand how wind power providing APC can benefit numerous parties by reducing total production costs, increasing wind power revenue streams, improving the reliability and security of the power system, and providing superior and efficient response, while limiting any structural and loading impacts that may shorten the life of the wind turbine or its components.

The three forms of APC focused on in this study are synthetic inertial control, primary frequency control (PFC), and automatic generation control (AGC) regulation. This project and report are unique in the diversity of their study scope. The study analyzes timeframes ranging from milliseconds to minutes to the lifetime of wind turbines, spatial scope ranging from components of turbines to large wind plants to entire synchronous interconnections, and topics ranging from economics to power system engineering to control design. The study captures a more holistic view of how each of these impacts and benefits can be realized.

Wind power plants have often been deemed a non-dispatchable resource and considered similar to inflexible demand. The rest of the power system resources have traditionally been adjusted around wind power to support a reliable and efficient system. In 2008, the New York

Independent System Operator (NYISO) started using wind power plants in its dispatch procedure to help manage transmission congestion at a five-minute resolution. Now, essentially all ISOs in the United States and many areas outside the ISO regions are utilizing wind power to provide this form of dispatch capability.

These regions have found the tremendous capability that wind power can provide in controlling its output to be extremely beneficial. This capability has been often ignored because wind power (along with other renewable resources) has a free fuel source, and therefore system operators have historically attempted to use as much wind generation as possible at all times. However, in many situations, due to minimum thermal generation levels and transmission constraints, it was cheaper to utilize less than the maximum amount of available wind power to provide this dispatch flexibility to assist the power system. These two concepts—(1) that wind power can provide support to the power system by adjusting its power output, and (2) that it may be economically advantageous to do so—should certainly be explored utilizing faster and more sophisticated forms of APC.

Many of the control capabilities being researched in this project have already been generally proven technically feasible, and a few areas throughout the world have already started to request or require wind plants to provide them. However, at least in the United States, wind power is rarely recognized as having these capabilities. This may be due to differences in perspective among various stakeholders (see Figure ES-1 below).

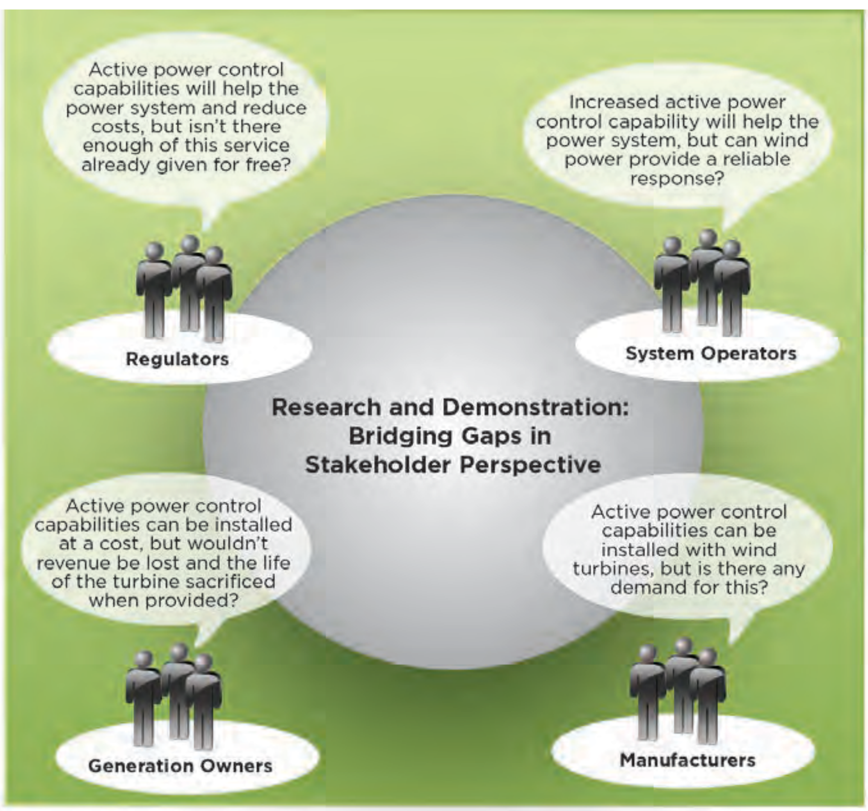


Figure ES-1. There may be different perspectives among various stakeholders on the feasibility, benefits, and economic justification for wind power to provide various forms of APC. This project bridges these gaps in perspective with research and demonstration.

For example, a manufacturer may know the capability is technically feasible but may not see a market for it because there is no demand from a developer or requirement from a utility off-taker to provide the capability. On the other hand, the system operators may desire the capability but be unsure of exactly how it performs or whether or not it will actually improve system reliability. The wind plant owners may know what features the turbines are capable of, but choose not to procure them or offer them to the off-taker if the functionality is not required or if it does not result in increased revenue. Finally, the regulators or market operators may not establish complementary policies or market designs if the markets are receiving enough capability and it is provided for free, without any outlook on how this may change in the future.

With this project's holistic research approach and extensive demonstration and dissemination plans, the team sought to close these gaps in perspective. If wind power can offer a supportive product that benefits the power system and is economic for the wind plant and consumers, this functionality should be recognized and encouraged.

The three forms of APC discussed in this study are inertial control, PFC, and AGC regulation. Brief descriptions are presented below. Figure ES-2 shows the result of aggregate APC response of system frequency following a loss-of-supply event. Figure ES-3 shows the response of balancing load and generation during normal conditions.

- **Inertial control**: Inertial control is the immediate response to a power disturbance based on a supply-demand imbalance. This response is currently given by synchronous machines that immediately inject (extract) kinetic energy of their rotating masses to (from) the grid, thereby slowing down (speeding up) their rotation and system frequency during loss-of-supply (-load) events. Aggregate inertial control will slow down the speed of frequency decline (see initial slope of frequency in Figure ES-2). Tests will analyze how wind power can bring out its own inertia through power electronics controls to provide immediate energy to reduce the rate of change of frequency.
- **PFC**: PFC is the response following inertial control that increases (decreases) the output of generators to balance generation and load during loss-of-supply (-load) events. This response is typically given by conventional generators with turbine governor controls that adjust output based on the frequency deviation and its governor droop characteristic. The aggregate PFC response will bring frequency to a new steady-state level (see Figure ES-2, 20–30 s after frequency drop). Tests will analyze how wind power can provide energy in this timeframe to assist in arresting frequency deviation, raising the frequency nadir (minimum frequency point) for a given loss of supply, and stabilizing the system frequency following a disturbance.
- **Regulation and AGC**: AGC is used during normal conditions and emergency events. Regulation, also called load frequency control and secondary control, is typically provided by resources with direction of an automatic control signal from a centralized control operator and is a response slower than PFC. The AGC response will bring frequency back to its nominal setting (which, in North America, is 60 Hz). This can be seen in Figure ES-2 at 5–10 minutes after the frequency decline. It also reduces the area control error (ACE) to ensure that frequency and interchange energy schedules between regions are kept to set points during normal conditions (see the red trace in Figure ES-3).

Tests will analyze how wind power can provide this control to stabilize frequency and reduce ACE.

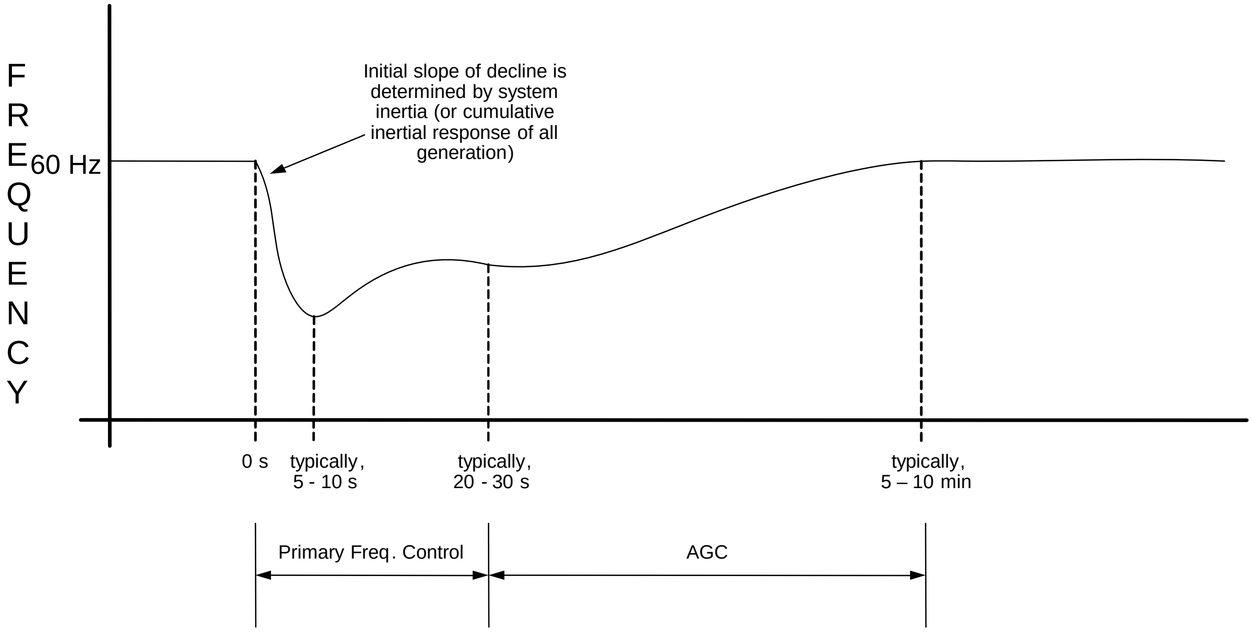


Figure ES-2. Frequency trace following a large contingency event (i.e., loss of a large generating unit). Inertial control, PFC, and AGC (secondary frequency control) each serve a different purpose, and their response timeframes are also at different points of the frequency recovery.

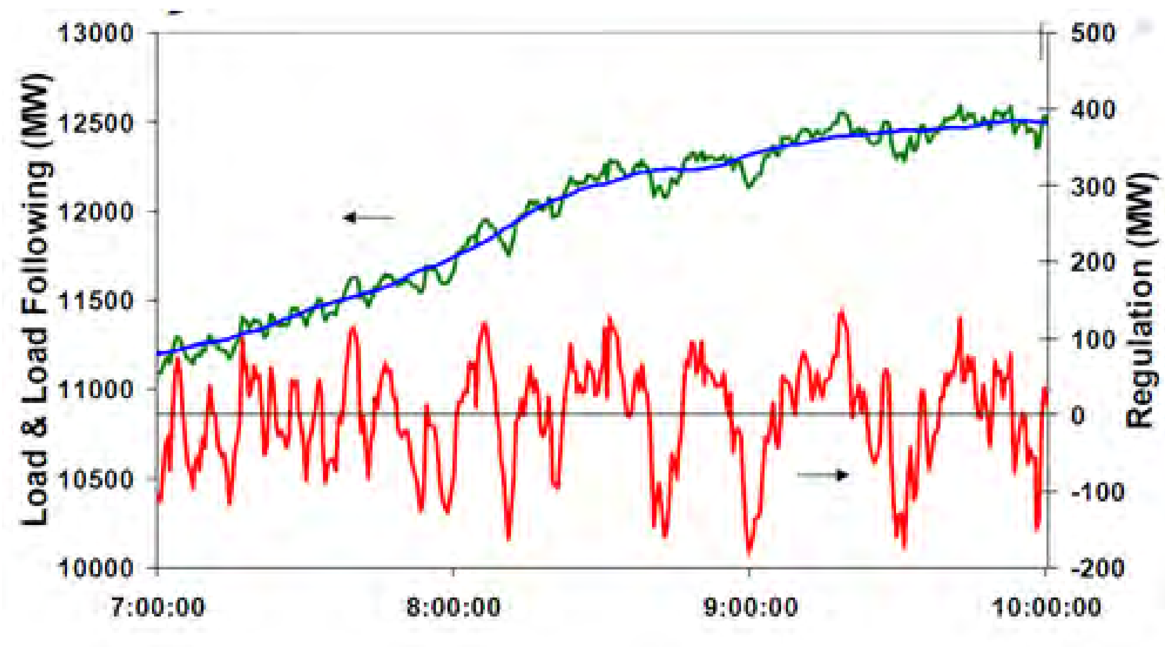


Figure ES-3. Regulation and load following during normal conditions.

For wind power to provide these three services, it is essential that three things happen.

First, the wind power response needs to improve power system reliability if it is provided, and not impair it. Wind turbines are quite different from conventional steam, combustion, and hydro turbines. The APC response provided will likely be different from the response from conventional plants, and it is essential that this response is analyzed and understood to support power system reliability. Second, it must be economic for wind power plants, as well as for electricity consumers, to provide these forms of APC, considering the additional capital costs for the controls. Also, when wind power activates these controls, it often must reduce the amount of energy it sells to the market. It would thus make little sense for wind to provide these controls if there are no incentives to provide it, or if it raises costs to electricity consumers. Third, providing the three forms of APC should not have negative impacts on the turbine loading or induce structural damage that could reduce the life of the turbine. The control design should be carefully optimized to provide a superior response, but ensure that it does so without adversely impacting the wind turbine or any of its components. Simulations and measured data in the field can show how different control strategies can impact loading.

This study sought to analyze each of these issues. While plenty of additional analysis and research can be performed to examine these topics even further, this is the first holistic approach aimed at addressing these questions together. Our analysis shows that wind power can support power system reliability by providing these controls, but the combination of these controls should be carefully considered. Our analysis also shows that forms of APC that currently have existing markets can allow wind to earn additional revenue and reduce production costs to consumers, although the magnitude of these revenues will highly depend on the trends of these markets, as typical prices are highly volatile. This study also analyzed how new ancillary service markets could be designed for the services that do not currently exist. Lastly, this study determined that any loading impacts caused from providing these controls are very small and, when considered with the benefits of reduced loading from de-rating the turbine, will actually have a positive effect on loading. Market designs, reliability criteria, the competitive field, and the evolution of the design for each of these controls will dictate future opportunities in various regions.

Economics and Steady-State Power System Impacts

The first task of this work focuses on the impacts of using wind power for APC on the steady-state operation of the power system, as well as the associated economic impacts. The goal of this task is to understand how wind providing APC affects steady-state operations, wind power revenue, and electricity production costs, as well as how markets may evolve to address new needs.

As an overview, below is the current status of each of the three APC services addressed in this report in terms of steady-state operations and U.S. market designs.

- **Inertial control status:** Inertial control on the system level is not a requirement in any region of the United States. It is inherently provided by synchronous machines (generators and motors). Hydro-Quebec is one system that has begun to require unit-specific inertia from wind generators. Inertial control is not explicitly scheduled for any resource, and there is no market or incentives to provide it in the United States.

- **PFC status:** PFC has a balancing area (BA) requirement in Europe and is in the process of becoming a requirement in North America. The North American Electric Reliability Corporation (NERC) is revising its BAL-003 requirement to incorporate frequency response requirements, which at the time of this writing are subject to FERC approval. In the Electric Reliability Council of Texas (ERCOT), rules require wind power plants to have the capability to provide PFC if they are operating at a point where they can do so (i.e., only if they were previously curtailed and have headroom to provide more energy during under-frequency events). There is currently no market or incentives to provide PFC in the United States, with the caveat that ERCOT requires any resources that are selected and paid by the spinning reserve market to be frequency responsive. It is not explicitly scheduled.
- **Regulation and AGC status:** Regulation is required on a BA level to meet the NERC CPS1 and CPS2 requirements. The requirements usually change based on load levels, day of week, season, and time of day. Restructured energy market regions have ancillary service markets that incentivize resources to provide regulation, and it is explicitly scheduled alongside the energy market in the unit commitment and economic dispatch models. As of the writing of this report, wind power currently does not provide regulation in any of the market regions of the United States.

The U.S. Eastern Interconnection has had a significant decline in its frequency response over the past 20 years. Many potential reasons have been discussed as the catalyst for this, but one of the major reasons is a lack of incentives for generators to provide PFC. In addition to the absence of incentives, there may be disincentives for market participants to provide PFC. Settlement systems may have financial penalties in place for generators that produce power at a level that is different from what they were asked to produce, without accounting for the source of the deviation. For example, a generator can be fined for producing at greater than a certain percentage from its scheduled output. Providing PFC will mean a generator's output will be dependent upon the system frequency when the frequency strays from its nominal setting.

The example equation below shows that for an area that has a 5% droop setting and a 3% tolerance band for under- or over-generating, current rules will result in any generator with a properly enabled governor that is assisting reliability to be automatically penalized with a 90 mHz frequency deviation. As rare as this may be, the fact that this risk is still present, and with a cost to the provision of PFC and without any incentive for providing it or any standard or grid code enforcing it, generators have every reason to disable their governors or operate in a way that provides little or no response.

$$\frac{1\, p.u. power}{0.05\, p.u. frequency} = \frac{0.03\, p.u. power}{X\, p.u. frequency}$$

$$X = 0.0015\, p.u. frequency = 90\, mHz\ for\ a\ 60\ Hz\ system$$

Four approaches were developed in this study to eliminate this disincentive and provide an incentive. The first two eliminate the penalty with different degrees of complexity, but they do not include a strong incentive for providing PFC. The third approach is to add a frequency response requirement to a separate ancillary service market, like the spinning reserve market.

While this would create an incentive for resources to be frequency responsive, it is difficult to combine two services that have different requirements and different costs.

The last approach is a separate PFC ancillary service market. This market would be similar to other ancillary services with some exogenous requirement, both in MW and in MW/Hz, that would result in a reliable system and avoid under-frequency load shedding following a very large, credible disturbance. This approach would effectively create the necessary incentives and link together the specific needs and costs of PFC. The major drawbacks to this approach are the complexity of the market software, increased data and compliance requirements, and the regulatory hurdles to obtain agreement from market participants and other stakeholders.

To illustrate the fourth approach, the study designed an example of a separate PFC ancillary service market. For wind power (and all other resources) to be able to provide PFC to support power system reliability and do so economically, incentives must be present. This design carefully incorporates the characteristics of inertia, PFC capacity, responsiveness of this capacity to frequency, limited insensitivity to frequency (i.e., keeping governor deadbands to a limit), faster triggering and deployment speeds, and a stable and sustainable response. The design also ensures the prices, auction bidding structure, and settlement rules are set in a manner to incentivize these characteristics. The design must also lead to an aggregate response that meets the system needs, making it both efficient and reliable. Finally, the market was designed to be applicable to systems that are part of large interconnected areas, such as those in the Eastern and Western Interconnections of the United States, as well as isolated systems, which have quite different characteristics given the interconnected nature of system frequency.

The model emulated that of a security-constrained unit commitment (SCUC)—the clearing engine that typically solves pool-based day-ahead markets. It took the characteristics of typical unit commitment models with the added constraints and inputs to incorporate the PFC market, which is coupled with the energy and other ancillary service markets through co-optimization. Droop curve settings, governor deadbands, and inherent thermal or hydrological time constants were all part of the inputs to determine the level of PFC a resource can provide. The design accounted for certain characteristics that were also supported in part by the load (e.g., the synchronous motor inertia and load damping characteristics). An iterative procedure between the SCUC and a dynamic frequency response model was developed to correctly emulate the speed of response.

Prices were designed to reflect the marginal cost theory. The PFC prices are based on the marginal cost to provide that service. As PFC is highly coupled with energy and secondary reserve services, it was co-optimized with these markets. Assuming the market operator considers capacity reserved for PFC to be a more critical need than spinning or non-spinning secondary reserve, a pricing hierarchy was followed so the PFC price was greater than or equal to the prices for those services. The pricing for inertial control was based on the marginal cost of inertia with relaxation of the integrality constraint of all units' online status. Lastly, a number of considerations were made for bidding and settlements, including market mitigation, cost allocation, bidding allowance, and compliance monitoring.

A number of case studies were examined with this market design using the IEEE Reliability Test System (3,000 MW peak). A first set of simulations was made with two base cases: the current market design without PFC, and the same design with the PFC market design incorporated (BC1: current; BC2: with PFC design). The second set of simulations added 15% wind power penetration to each simulation, where the wind power was asynchronous and without any PFC capabilities (WC1: current; WC2: with PFC design). These comparisons are shown in Table ES-1 and Table ES-2 below. The comparison with the wind power systems had a greater difference in results between cases than the simulations without wind. In the wind cases, the system without a PFC market design provided for much less PFC than when the PFC requirement market was introduced, and could potentially have led to a greater possibility of reliability issues (the requirement of total PFC on this system is 44 MW). The relative cost difference between the wind cases was also greater, meaning it cost more to retrieve the required PFC on the system with a greater percentage of asynchronous resources.

In all cases, the amount of inertia was not significantly changed, meaning that the PFC market did not impact the amount of inertia in the system, mostly because enough inertia to meet requirements was typically met inherently due to energy and secondary reserve requirements. Additional studies were performed to further analyze this market design. It was found that extreme penetrations of asynchronous resources could lead to inertia pricing benefiting the reduction of inefficient make-whole payments. It was also found that improving certain capabilities, like reducing the governor deadband, would lead to increased revenue for an individual generating unit, meaning the incentives built into this market design could lead to innovation and improvements to PFC capabilities. If designed in this manner, the market could likely lead to enough incentive for wind power plants to install these capabilities and provide PFC when the market incentivizes them to do so.

Table ES-1. Base Case Comparison

	BC1	BC2
Production Costs ($)	568,297	569,315
Avg. Units Online per Hour	20	19
Avg. Inertial Energy per Hour (MVAs)	8563	8618
Avg. $P1^{ss}$ per Hour (MW)	43.7	48.4

Table ES-2. Wind Case Comparison

	WC1	WC2
Production Costs ($)	401,287	403,616
Avg. Units Online per Hour	17	17
Avg. Inertial Energy per Hour (MVAs)	7283	7310
Avg. $P1^{ss}$ per Hour (MW)	36.75	48.1

A final part of this task analyzed the potential for wind power plants providing AGC regulation in a system that included a regulation ancillary service market. The study was performed on the California Independent System Operator (CAISO) system, simulating its energy, regulation up, regulation down, and other ancillary service markets during a two-month period. A summary of the costs for CAISO and the rest of the Western Interconnection is shown in Table ES-3 for a case without regulation provided by wind, and one where wind is allowed to provide up to 20% of the regulation up and regulation down requirements.

Table ES-3. Cost and Import Level Impact for Western Interconnection and California

Case	Western Interconnection Costs ($)	CAISO Costs	CAISO Start-Up Costs	Net Import to CAISO (GWh)
NoWindReg	$5,610M	$1,550M	$27.9M	7,359
WindReg20	$5,607M	$1,531M	$26.3M	7,626
Change	-$3.1M	-$19.5M	$1.6M	267
Change (% of Base)	-0.2%	-1.3%	-5.7%	3.6%

The cost reductions for the Western Interconnection were relatively small (0.2%), while the cost reduction for CAISO was greater (1.3%). The total revenue increase for CAISO wind power was $5.5M, or $1/MWh, a small but not insignificant number. If wear-and-tear costs or efficiency penalties were included in the thermal generation costs, both cost reductions and revenues could increase. CAISO also shows almost a 6% reduction in start-up cost when wind is providing regulation. The fast control available from wind power to provide this service could also benefit from new "pay-for-performance" market design schemes via new revenues. However, the potential impact of forecast errors on the ability to provide the full dedicated regulation response could influence how much of it system operators are willing to allow wind power to provide. All of these issues should be pursued in more detail to understand how wind can participate in the regulation market.

Dynamic Stability and Reliability Impacts

Increased variable wind generation can have a number of impacts on the dynamic stability and reliability of the power system. Lower system inertia was identified as one such impact, as it would result in faster-declining frequency during large loss-of-supply events, resulting in a greater risk of lower frequencies that can lead to voluntary load-shedding, machine damage, or even blackouts. A decrease in system inertia will necessitate an increase in the requirements for PFC reserves in order to arrest frequency at the same nadir following a sudden loss of generation. Similarly, a decrease in PFC can result in lower steady-state frequencies, also leaving the system at greater risk.

In order to properly study these dynamic impacts on power system reliability, the wind plant generator dynamic models must be understood, and so must the types of frequency events that occur on these systems. Significant penetrations of wind on the system without APC can then be studied to see how much system frequency performance is degraded. Adding APC to the wind plants can then be studied to show how much it improves the response and reliability.

Electrical generator models must be developed that appropriately model the ways that wind power plants can provide APC. This study examined the characteristics of the four types of wind plants and how each can provide various levels of synthetic inertial control or PFC. The most popular form of wind turbine generators, those of variable speed, can provide a power boost (similar to inertial control) during frequency events as long as the generator, power converter, and wind turbine structure are designed to withstand that overload. These types can also provide PFC, given a level of reserve capacity.

It is important that the generators are maintained at a constant tip-speed ratio and that the pitch angle is controlled so that the rotor speed follows the target speed. Wind power plants have the flexibility to adjust droop curve settings, inertia constants, and governor deadbands depending on system needs and requirements. Wind power can also respond to new designs like non-symmetric or non-linear droop curves, if desired.

Frequency events were recorded on both the U.S. Eastern and Western Interconnections since 2011. These data were used to better understand the types of events that occurred on each interconnection and the typical frequency nadirs, settling frequencies, ratios between nadir and settling frequency, and overall distribution of frequency. Figure ES-4 shows a histogram of frequency nadir (top) and settling frequency (bottom) for the Western Interconnection for significant frequency events recorded during 2011–2013. These data were also used for the field testing discussed later so that the wind turbine tests used actual frequency to reflect realistic responses.

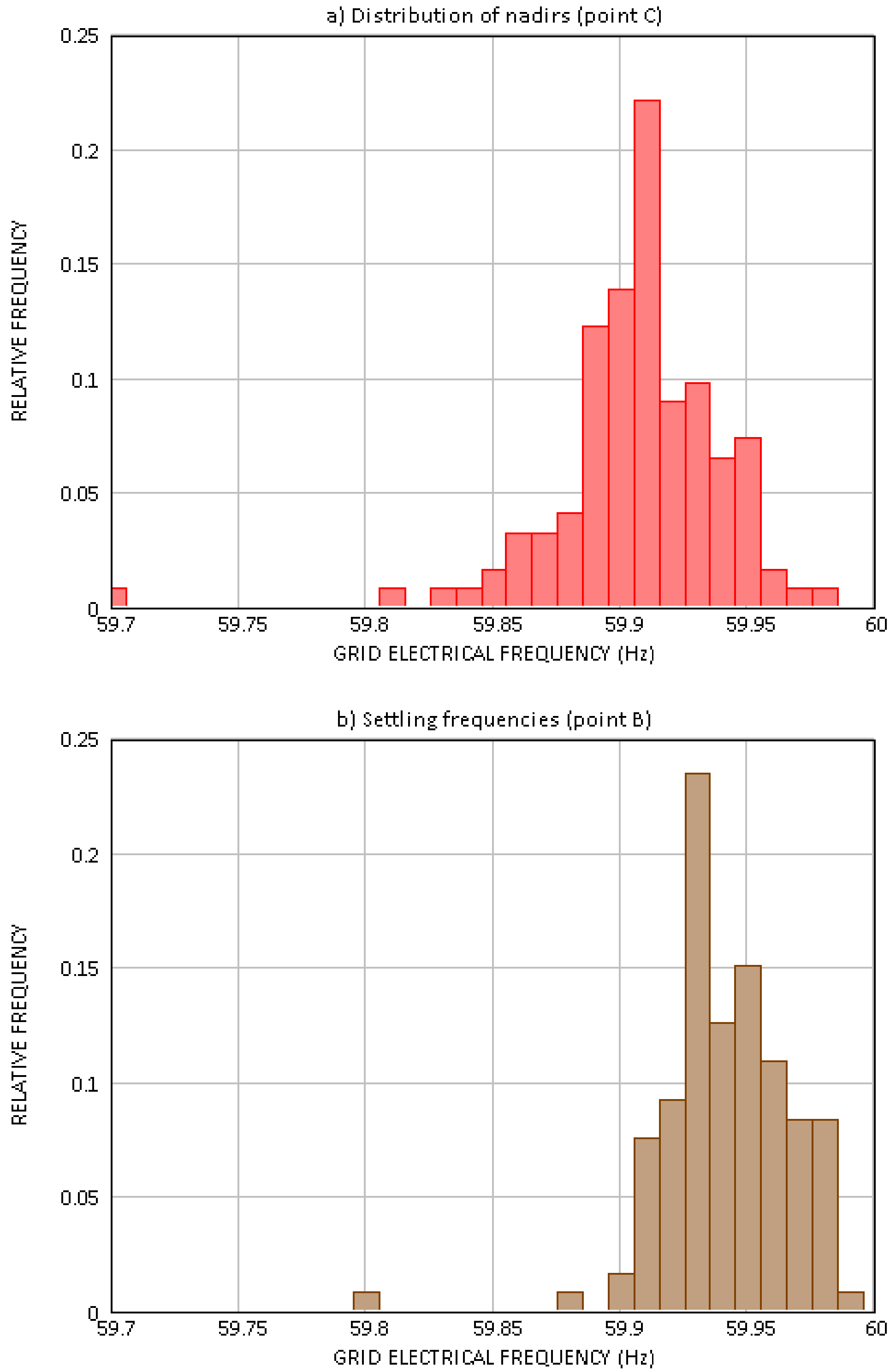


Figure ES-4. Distribution of low-frequency event data. Point C is the frequency nadir and point B is the settling frequency.

The team performed a study on the Western Interconnection with up to 50% instantaneous wind penetration. The purpose of the study was to analyze how the system would meet the new frequency response obligation requirements being proposed (i.e., the BAL-003-1 NERC standard). A very large disturbance was simulated (two large nuclear units at 2600 MW) and the frequency response was analyzed. Scenarios were performed at 15%, 20%, 30%, 40%, and 50% instantaneous wind penetrations for four cases: 1) normal wind power plant operation without APC, 2) providing inertia only, 3) providing PFC only, and 4) providing both inertia and PFC. The results are shown in the figures below for frequency nadir (Figure ES-5) and settling frequency (Figure ES-6).

The ability of wind plants to provide PFC was shown to be tremendously beneficial in this study. At very high penetrations, it was shown that when wind power plants provide synthetic inertia only, it can actually result in a lower frequency nadir than if the plants provided nothing at all (assuming all wind plants are at below-rated wind speeds). However, a combined inertia and PFC response from these plants significantly improved the frequency nadir and settling frequency at all wind penetration levels. Further study analyzed the effect of the percentage of conventional generators providing frequency response as well as the impact of reduced response from conventional generators combined with various wind APC strategies and wind penetrations on the response given by other generators on the system.

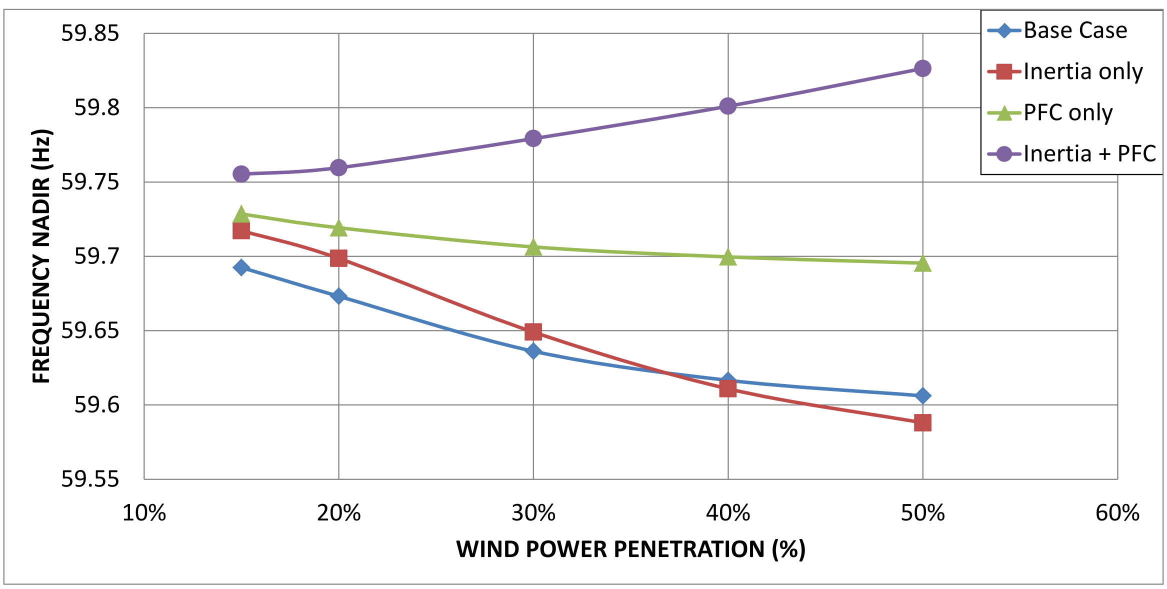


Figure ES-5. Impact of wind power controls on frequency nadir.

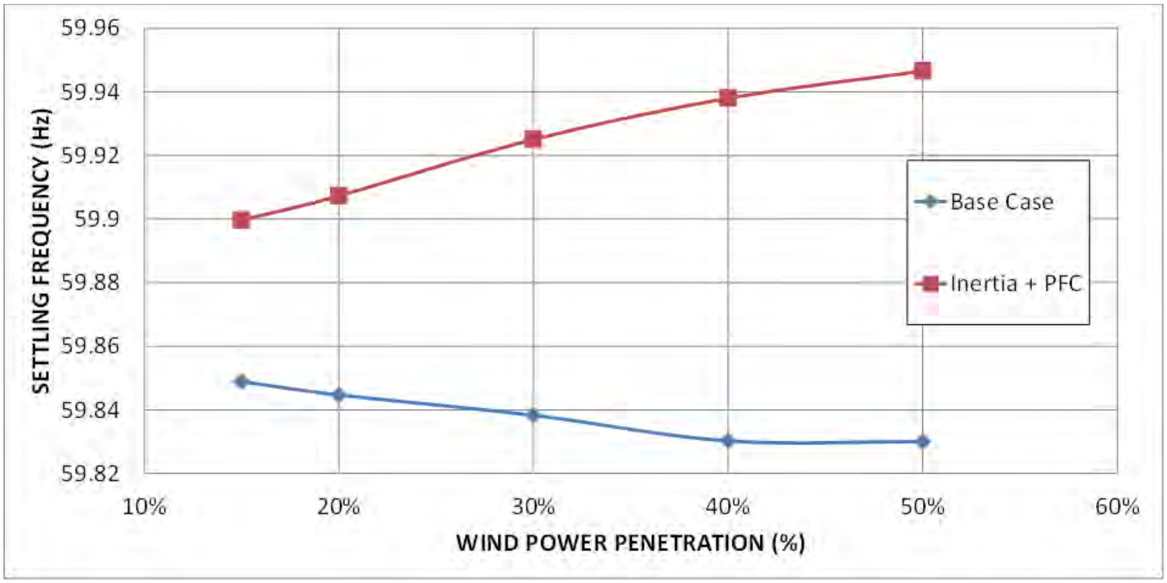


Figure ES-6. Impact of wind power controls on settling frequency.

Controller Design, Simulation, and Field Testing

The final task of this study examined APC designs and their performance using both simulations and field tests. This work focused on developing and testing new controller designs that are capable of simultaneously actively de-rating, following an AGC command, and providing PFC. Furthermore, this task evaluated the structural loading induced by the various APC designs. The controllers were designed in an environment (Simulink) that can be directly ported to the 3-Bladed Controls Advanced Research Turbine (CART3) for field testing at the NWTC.

Several control systems were designed and evaluated in this task for providing the various APC services (power reserve, AGC following, and PFC). These methodologies were combined into a single adjustable controller called the torque-speed tracking controller (TTC). The controller allowed for implementation in simulation or field testing of the various approaches to power reserve, AGC following, and PFC provision, and in various combinations. Additionally, the controller featured adjustable design parameters, which allowed tradeoff analysis between aggressive responses and structural loads.

This design was used in simulation to understand the impact of different control designs on structural loads. Damage equivalent load (DEL) is a standard metric for comparing fatigue loads in wind turbine components. Figure ES-7 shows the DEL with the use of TTC with a 10% de-rating (i.e., operation at 90% of maximum available power), with and without the provision of AGC regulation, normalized to the DELs from the traditional maximum power capture strategy. As can be seen, the participation in continuous AGC has very little impact on the overall DEL.

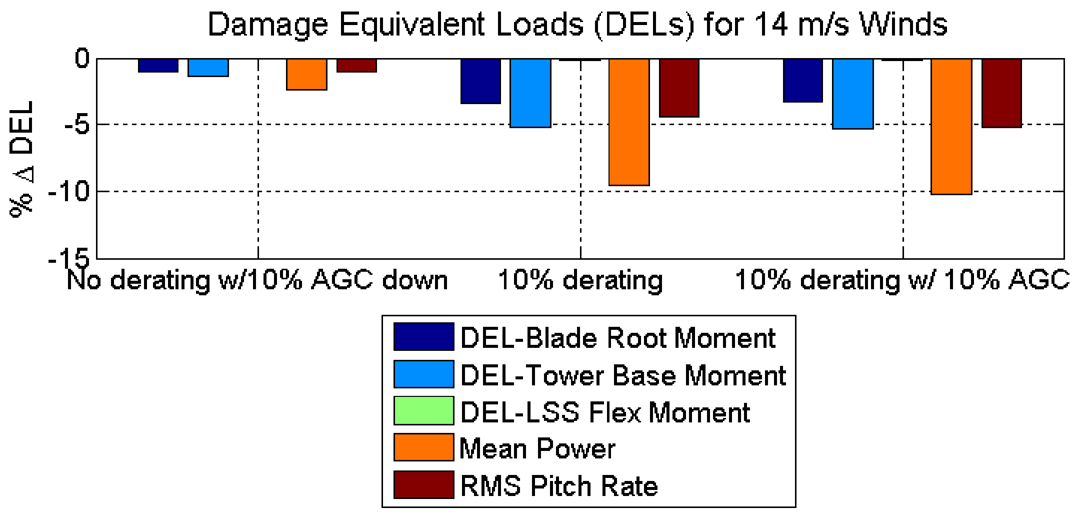


Figure ES-7. The induced DELs on turbine components comparing de-rating and AGC utilization.

The team also performed field tests at the NWTC using the 600 kW CART3 wind turbine with both AGC and PFC tests. First, field tests were performed to evaluate a wind speed estimator that was necessary for de-rating modes in understanding the amount of available power in the wind. The first chart in Figure ES-8 shows a field test where the turbine was given a de-rate command, followed by a simulated under-frequency event. The response followed both the de-rate command and the provision of PFC. The high-frequency fluctuations seen would likely be smoothed out significantly when the entire wind plant is being considered, rather than just a single turbine.

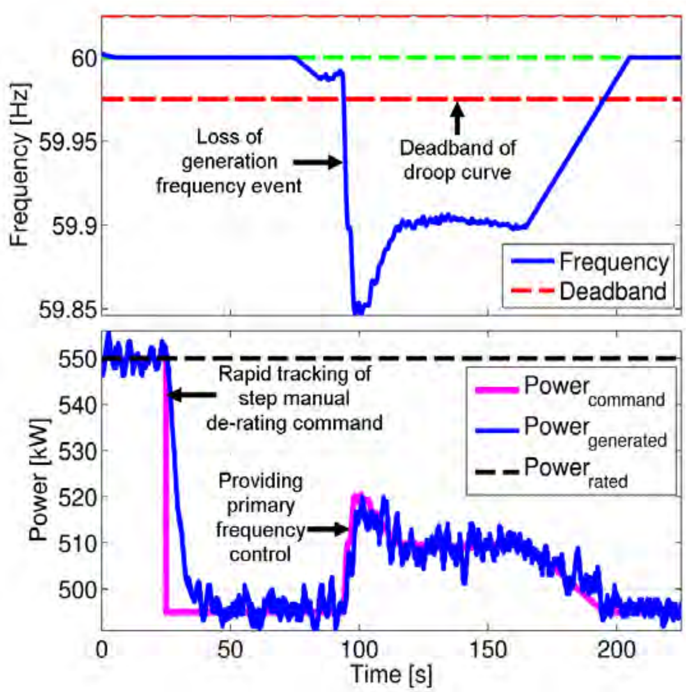


Figure ES-8. Field test data that shows the turbine tracking a step change in the de-rating command followed by PFC response to an under-frequency event.

The second chart in Figure ES-9 shows the CART3 following an AGC command, which is derived from actual ACE data from a Western Interconnection BA. In this chart, a few instances of reductions in the de-rating command occur when the available wind power drops below the rated power. The figure shows how the controller estimates the power available in the wind (P_{avail}), de-rates with respect to the estimation so that there is power overhead to follow the AGC command ($P_{cmd\ Dr}$), and then tracks this level plus the AGC command ($P_{cmd\ Dr\ +\ AGC}$). The signal P_{gen} is the actual output power, which effectively tracks the desired output power even given the varying wind conditions. Again, it is likely that the high-frequency fluctuations of this response would be reduced when considering the entire wind plant.

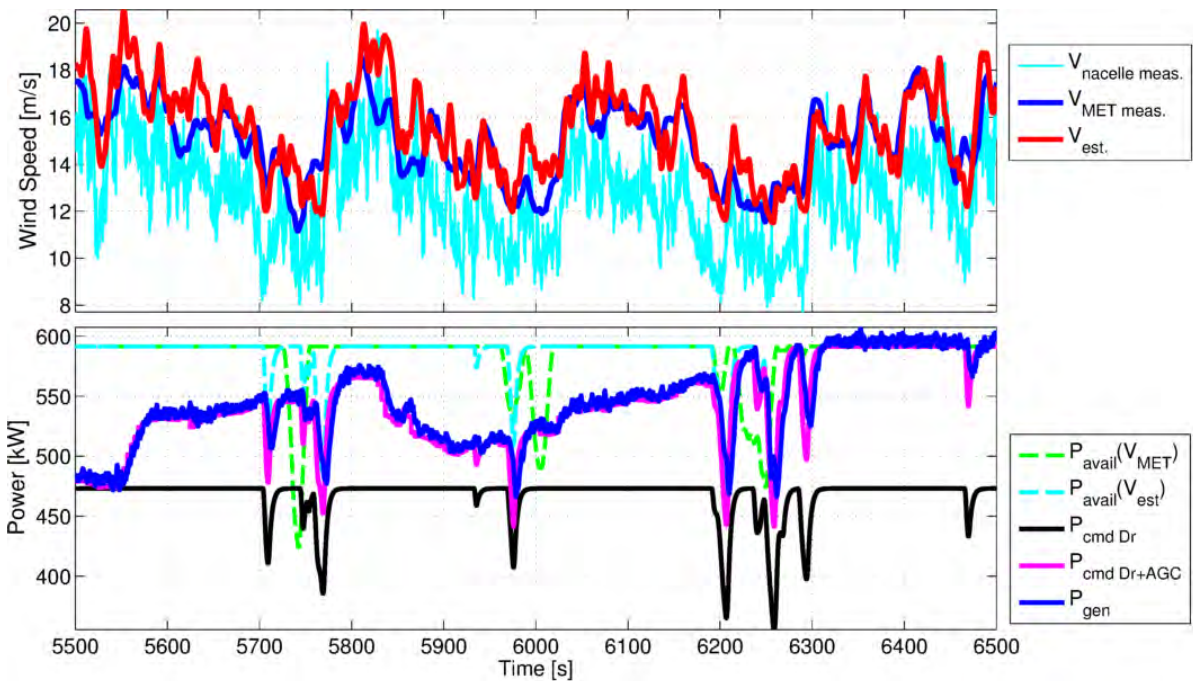


Figure ES-9. A field test of the CART3 turbine following an AGC command.

Conclusions and Next Steps

This study provides a number of insights into the practicality of wind power plants providing the finest forms of APC to support power system reliability. A number of steady-state, dynamic, and machine-level simulations as well as field tests were conducted to understand the benefits and impacts of wind plants providing this response.

These studies just start the conversation, and numerous opportunities exist for fine-tuning this research. Simulations, and especially field tests, that model the entire wind-plant-level controls are needed to produce more realistic results. Improved control designs with advanced tracking technologies like LIDAR can also improve the response performance. A better understanding of the interaction between regulation and PFC, which are responses typically simulated with different tools, should be achieved so that any reliability issues that occur between the seams of these two timeframes can be assessed. Further economic studies can also show the impact of transmission, forecast error, and new rules like the "pay-for-performance" regulation rule (based on FERC Order 755) on the revenue streams and production cost reductions of wind power plants providing these services.

The studies detailed in this report have shown tremendous promise for the potential for wind power plants to provide APC. Careful consideration of these responses will improve power system reliability. Careful design of the ancillary services markets will result in increased revenue for wind generators and reduced production costs for consumers when these services are provided. Careful design of control systems will result in responses that are in many ways superior to those of conventional thermal generation, all while resulting in very little effect on the loading and life of the wind turbine and its components. With all these benefits that may result from careful engineering analysis, there should be no reason that wind power plants cannot provide APC to help support the grid, and help wind power forever abandon its classification as a “non-dispatchable” resource.

Exhibit 14

U.S. DEPARTMENT of ENERGY

Research Suggests Wind Turbines Can Provide Grid Reliability and Flexibility

Sandia researchers demonstrated that modulating the rotation speed of wind turbine rotors can offer two important grid services.

Wind Energy Technologies Office

October 12, 2018

3 minminute read time

Sandia National Laboratories (Sandia) researchers, collaborating with Group NIRE and Baylor University, demonstrated that modulating the rotation speed of wind turbine rotors can offer two important grid services—load balancing and stability management—among other potential benefits to provide flexibility and resilience on the grid.

Load Balancing

A typical generator in a power plant has the ability to respond to sudden increases in power demand by sensing that more energy is being pulled from the plant than what is being produced. This response is triggered by detecting the reduction of rotating kinetic energy of the generator's turbine. In other words, when the turbine slows down instead of remaining at its usual speed, the plant controls recognize that the plant needs to produce more power.

Wind turbines also have the ability to balance loads and support grid stability despite fluctuating energy demands. Sandia, Group NIRE, and Baylor demonstrated that by modulating the power output of a Vestas V27 wind turbine at the Scaled Wind Farm Technology (SWiFT) facility, they could provide up to six times the stored energy of a conventional synchronous generator (per MW nameplate) with only a 0.12% drop in aerodynamic efficiency. This research may help identify operating practices that could allow turbines to run at higher efficiencies while still being able to respond to surges in demand.

Stability Management

The research also demonstrated that controlled power modulation of a wind turbine can mitigate oscillations in the grid. Oscillations occur as power is transmitted across long transmission lines, such as region to region. If oscillations are poorly damped, they can jeopardize grid stability and can lead to widespread outages during stressed grid conditions.

Using a modified control algorithm from a prior test of the Pacific DC intertie—a power transmission line spanning the Pacific Northwest to Los Angeles—Sandia, Baylor, and Group NIRE simultaneously tested whether it would be feasible to use the same rotor modulation technique to dampen inter-area oscillations. Using a grid-connected Vestas V27 Wind turbine at SWiFT, a control system at Sandia's Control and Optimization of Networked Energy Technologies Laboratory, and phasor measurement units on the grid, the team successfully tested the ability *to use* a wind turbine to supply load balancing reserve energy and stabilize a wide-area grid.

Although additional research is needed into the operations and maintenance costs of turbine modulation, initial results indicate that wind turbines could be a significant source of flexibility and resilience on the grid, in addition to contributing valuable grid services and a new, potential source of revenue for wind plant operators.

The results are publicly available from Sandia National Laboratories in the report, "*Use of Wind Turbine Kinetic Energy to Supply Transmission Level Services*."

Wind.turbines.could.be.a.significant.source.of.flexibility.and.resilience.on.the.grid?.
according.to.research.conducted.at.the.Scaled.Wind.Farm.Technology.facility¡

Photo courtesy of Sandia Nation.

Exhibit 15

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 State of Reliability Overview

June 2024

[2024 SOR Infographic]

[2024 SOR Technical Assessment]

[2024 SOR Video]

Assessment Overview of 2023 Bulk Power System Performance

Table of Contents

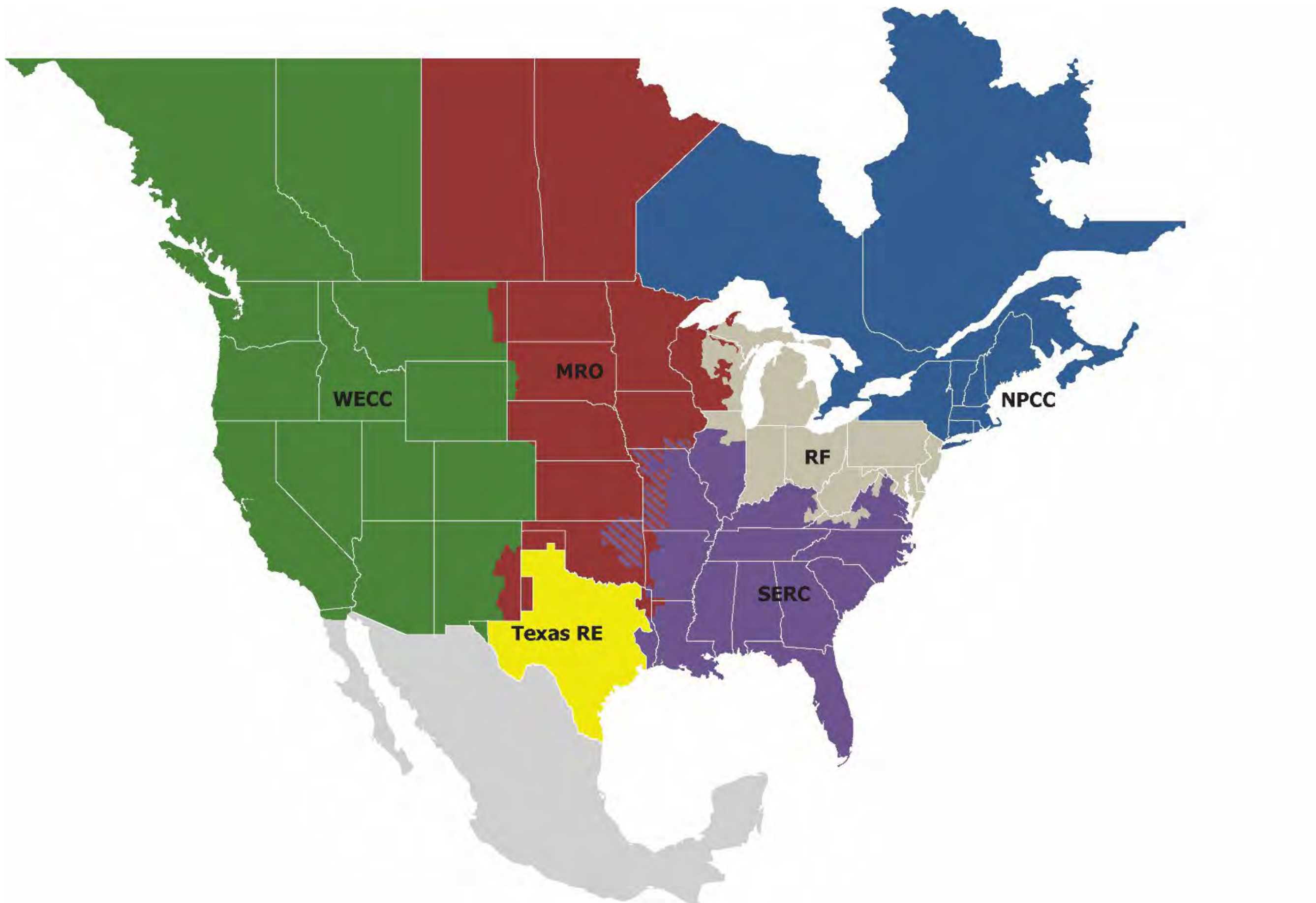
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Transmission Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Overview

This year's *State of Reliability* (*SOR*) report is comprised of two publications: this *2024 SOR Overview*, which is a high-level summary of the Technical Assessment, summarized by key findings, and the *2024 SOR Technical Assessment*,[1] which provides NERC's comprehensive annual analytical review of BPS reliability for the 2023 calendar year. This analysis fulfills a key role in NERC's mission by providing an unbiased, data-driven look at BPS reliability, identifying ongoing challenges and informing future-looking assessments. This overview seeks to inform regulators, policymakers, and industry leaders on the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken and will take to address them.

The *2024 SOR Overview* replaces the key findings previously found in the Technical Assessment.

Development Process

ERO staff developed this overview and the corresponding *2024 SOR Technical Assessment* with support from the Performance Analysis Subcommittee. It draws conclusions from an established set of reliability indicators and mandatory information reported by industry to the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), voluntary reporting into the Event Analysis Management System (TEAMS), Bulk Power System Awareness monitoring and processes, and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group.

Considerations

- Data in the *SOR* represents the performance for the January–December 2023 operating year unless otherwise noted.
- Analysis in this report is based on data from 2019–2023 that was available in Spring 2024, and it provides a basis to evaluate 2023 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- To properly demonstrate key trending information, this year's report evaluates generation data dating back to 2014.
- The *SOR* is a review of industry-wide trends and not a review of the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection is combined with the Eastern Interconnection unless specific analysis for the Québec Interconnection is shown.

[1] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf

Key Finding 1: Response to Severe Weather Events Confirms the Overall Resilience of the BPS

Over the past several years, a handful of extreme weather events has increasingly been the largest challenge to BPS reliability, and the unprecedented magnitude of these events has dominated reliability trends. In 2023, the absence of such anomalous events in the United States showed that the BPS performed well based on the more routine (but still severe) weather events (see Figure 1).

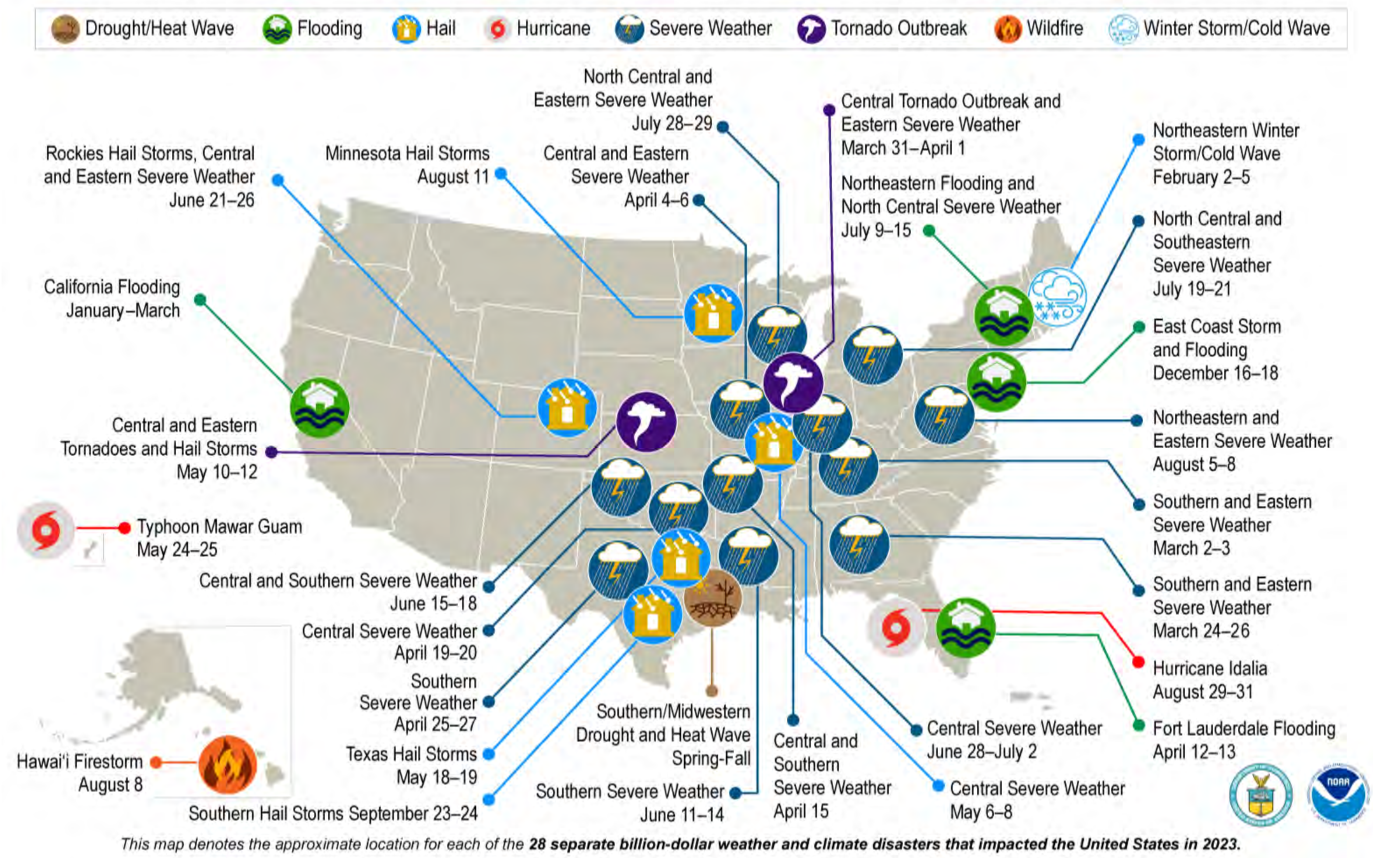
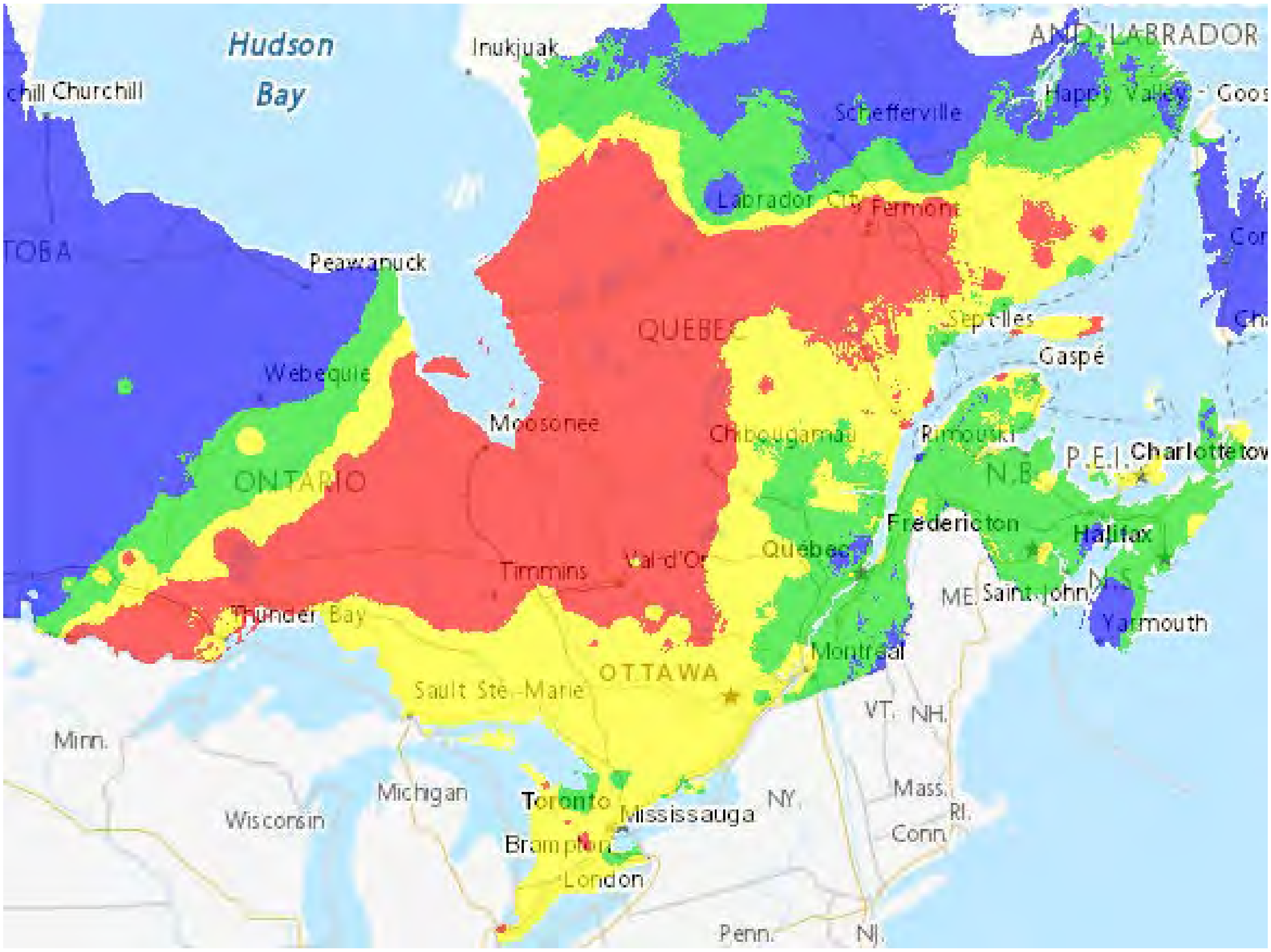


Figure 1: 2023 U.S. Billion-Dollar Weather and Climate Disasters[2]

Canada experienced record-setting wildfires throughout 2023. Transmission metrics were disproportionately impacted by the short-duration outages associated with these wildfires, specifically within the Québec Interconnection. However, due to operator actions as well as the fires' varied timing and geographical locations, the actual impact on BPS reliability was minimal (see Figure 2).

[2] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023). https://https://www.ncei.noaa.gov/access/billions/, DOI: 10.25921/stkw-7w73



Fire Danger – Provincial/Territorial Classifications

Low
Moderate
High
Very High
Extreme

Figure 2: Fire Danger in Canada, June 20, 2023[3]

Overall, the worst-performing days (as measured by the severity risk index) showed significantly better performance than the worst-performing days observed in prior years (see Figure 3). Following these more routine, severe events in 2023, restoration times of transmission system outages were 10–20% better than in most prior years, and no load loss associated with Level 3 Energy Emergency Alerts occurred.

[3] Natural Resources Canada, June 20, 2023

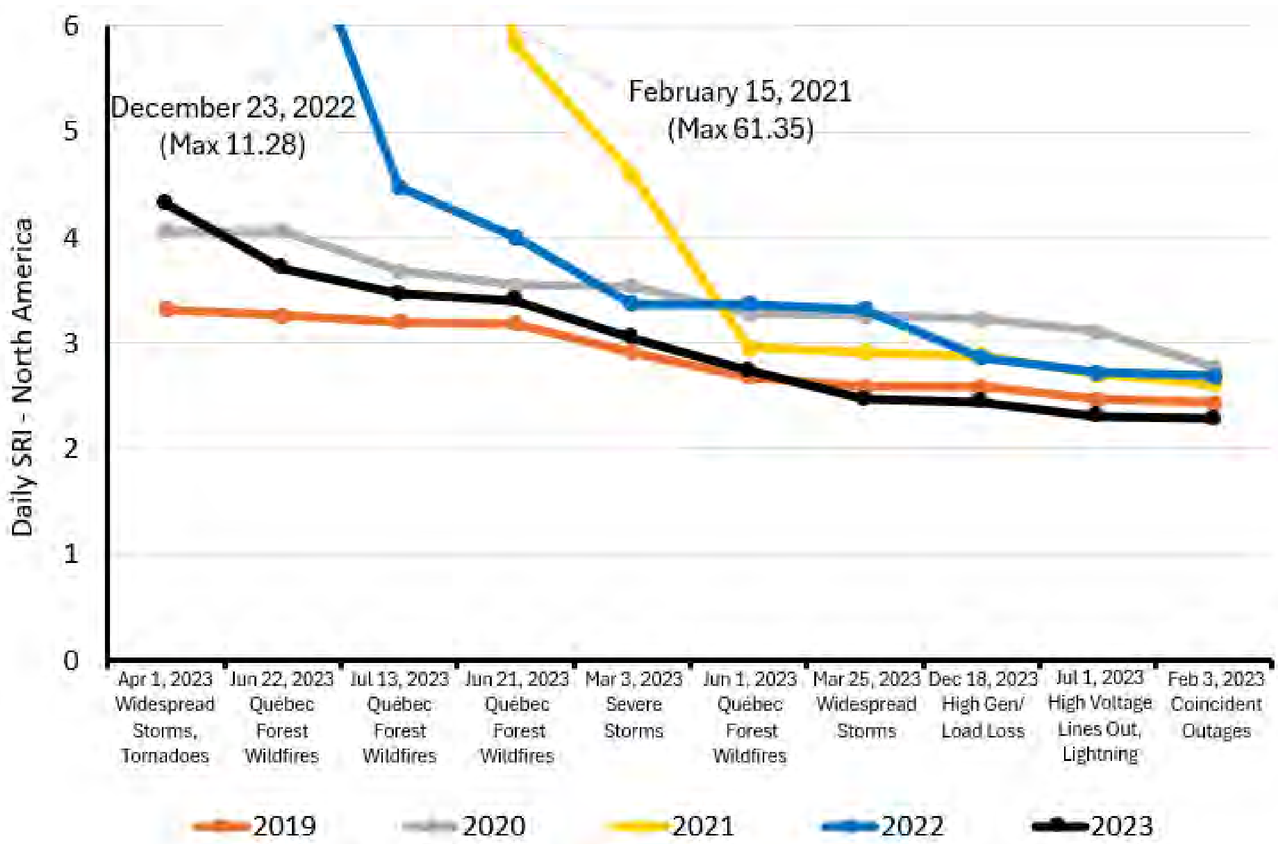


Figure 3: Top Annual Daily SRI Days Sorted Descending

This finding highlights the ability of the BPS to withstand severe weather events, demonstrating the importance of advanced preparation, active management engagement throughout the duration, and rapid restoration following an event.

Resultant Actions

- Increased ERO Enterprise focus on periods of extreme and abnormal weather conditions, through inquiries and other event analyses, has produced recommendations for revisions to Reliability Standards, increased cold weather alerts, and additional data collection to monitor performance.
- EOP-011-2[4] was issued to address the effects of operating emergencies by ensuring that each Transmission Operator (TOP), Balancing Authority (BA), and Generator Owner (GO) has developed plans to mitigate operating emergencies and that those plans are implemented and coordinated within the Reliability Coordinator area as specified within the requirements. This standard became enforceable in 2023.

[4] EOP-011-2

Key Finding 2: Generation Forced-Outage Rates Continue to Increase

Conventional and wind generation forced-outage metrics remain at historically high levels, exceeding rates for all years prior to 2021. Despite no major events comparable to Winter Storms Uri or Elliott, the weighted equivalent forced-outage rates (WEFOR) of baseload coal and cycled natural gas units[5] remained high in 2023 (see Figure 4), remaining the primary drivers for the high conventional generator outage rates. While performance of any fuel type may vary during a single event, the annual WEFOR for natural gas units has remained relatively consistent. Although hydro generation also experienced relatively high forced-outage rates for this class of resource, these plants represent a much smaller portion of the conventional fleet and do not contribute as much to the WEFOR.

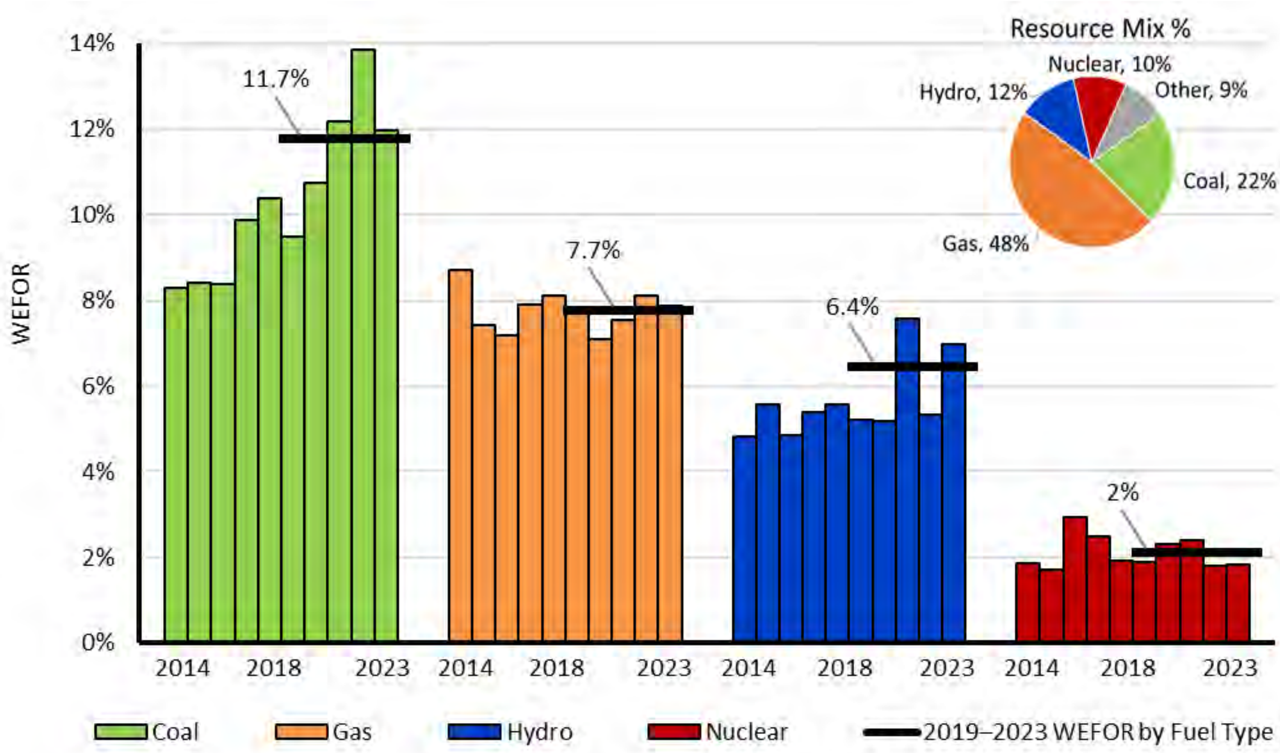


Figure 4: 10-Year Annual Coal WEFOR 2023 Resource Mix by Net Maximum Capacity

Due to year-over-year variability, coal generation most closely correlates to the overall WEFOR, despite more energy being produced by both natural gas and nuclear power in 2023 (see Figure 5). There is a slight correlation between the age of coal units and WEFOR; however, the WEFOR of coal units is affected more by an increase in maintenance and a reduction in service hours than an increase in forced outages.

As baseload coal units continue to be retired and require more maintenance, they are increasingly being replaced by a mixture of inverter-based resources (IBR) and periodically run gas turbines. Industry statements related to reduced investment in maintenance and abnormal cycling, which are being adopted primarily in response to rapid changes in the resource mix, are negatively impacting baseload coal unit performance. This aligns with analysis showing that baseload coal units operating below a 60% capacity factor experience a disproportionate increase in outage rate.

[5] Figure 4 presents all generators for a given fuel type. Frequently cycled natural gas generation shows a higher WEFOR; however, overall natural gas generation's WEFOR has remained relatively stable.

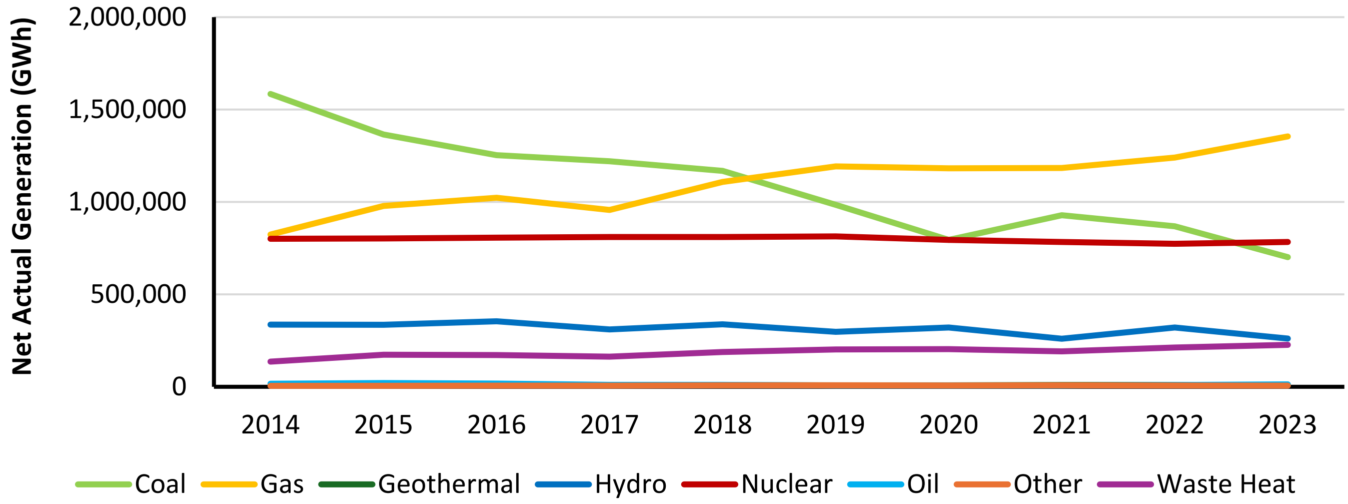


Figure 5: 10-Year Annual Conventional Net Actual Generation (GWh) by Fuel Type

The weighted resource forced-outage rate continues to increase for wind generation, up to 18.9% overall compared to 18.1% in 2022. While not an exact comparison to the WEFOR used to measure performance of conventional generating units, the continued increase is of concern given the growth in wind generation over recent years. New and expanded reporting requirements for conventional and renewable generation went into effect in 2024. This will allow for expanded analysis of the performance of IBRs in future reports and more detailed analysis of conventional generating units.

Resultant Actions

- Decreasing baseload coal generation reliability, in combination with increasing variable resource generation, will necessitate increased reserve margins.
- As the BPS becomes more reliant on energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable system operation. To address these concerns, NERC standards BAL-007-1[6] and BAL-008-1[7] have been prioritized for release in 2024. These standards will require operating entities to assess the risks associated with energy emergencies in the near-term and seasonal time horizons and take appropriate actions.
- The *Long-Term Reliability Assessment* (*LTRA*), *Summer Reliability Assessment*, and *Winter Reliability Assessment*[8] continue to analyze a variety of possible future scenarios and identify preventive measures. In recent years, NERC has enhanced the risk analysis in the summer and winter reliability assessments by incorporating deterministic risk scenarios involving generator forced-outage rates under typical and more extreme conditions. NERC's *LTRA* includes a probabilistic assessment (ProbA) of supply shortfall risk, considering hourly profiles of demand, variable energy resource performance, and generator outages. The ProbA identifies expected amounts of unserved energy and load-loss risk that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis.
- NERC and industry continue to develop enhanced approaches to assessing resource adequacy as the resource mix evolves. The NERC Reliability and Security Technical Committee (RSTC) created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[9]

[6] BAL-007-1
[7] BAL-008-1
[8] Reliability Assessments
[9] ERAWG

Key Finding 3: Performance of Inverter-Based Resources[10] Continues to Impact the BPS

IBR events continue to challenge BPS reliability, especially since IBR disturbance response is no longer limited to solar facilities. The southwest Utah disturbance in April 2023 and the California battery energy storage disturbances in March and April 2022 indicate this, and an upcoming NERC–Texas RE joint report will identify similar impacts to wind. The unexpected loss of generation and lack of ride-through support from these types of resources create system stability challenges. ERO Enterprise oversight and mitigation of these risks should be highly prioritized as IBRs grow in magnitude and increase as a share of the generation mix, especially in the Texas and Western Interconnections.

A second 2023 event occurred in the same southwest Utah area in September 2023, involving 90% of the same facilities. Software updates that were implemented in coordination with equipment vendors improved system disturbance response, reducing the generation loss by nearly 50% from the April event. This reduction demonstrates that the issues can be (at least partially) addressed through software updates.

Resultant Actions

- Inverter software upgrades to affected facilities in California increased the threshold for dc bus unbalance tripping, faster activation of stronger dc balancing, and low-voltage ride-through mode.
- California Independent System Operator (CAISO) updated the technical requirements of its pro forma large generator interconnection agreement (LGIA), requiring the plant controller to be coordinated with the inverters so that that the plant controller does not restrict inverter reconnection following the clearance of a low-voltage transient.
- NERC issued a Level 2 Alert on Inverter-Based Resource Performance Issues[11] to collect data and provide specific recommendations to industry to reduce the systemic performance issues identified in multiple disturbance reports. The data collection effort included responses from 521 generation facilities and 15 inverter manufacturers, representing over 53,500 MW of solar capacity. The Federal Energy Regulatory Commission (FERC) issued an order in Docket RD22-4,[12] Registration of Inverter-Based Resources. NERC is working with industry to make changes to the Rules of Procedure to specify registration requirements for IBRs.
- FERC Order 901[13] directed NERC to develop new or modified Reliability Standards that address reliability gaps related to IBRs in data sharing, model validation, planning and operational studies, and performance requirements. Multiple IBR-related high-priority standards projects are slated to be completed in 2024, including new IBR performance requirements.
- FERC Order 2023[14] requires interconnection customers requesting to interconnect an asynchronous generating facility to provide the Transmission Provider with the models needed for accurate interconnection studies. Additionally, interconnection customers must maintain power production at pre-disturbance levels as well as dynamic reactive power to support system voltage during transmission system disturbances. The rule also requires that all newly interconnecting large generating facilities provide ride-through capability consistent with any standards and guidelines that are applied to other generating facilities in the BA area.
- Section 1600 data collection to collect GADS performance and event data from IBR wind, solar, and battery energy storage system (BESS) resources begins in 2024. This data will be used to further analyze IBRs and refine performance trends and metrics.

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[10] IBRs include solar photovoltaic (PV), Type 3 and Type 4 wind, BESS, and fuel cell.
[11] NERC Level 2 Alert Focused on Inverter-Based Resource Performance Issues for Generator Owners, March 14, 2023.
[12] FERC Docket RD22-4-000 (Docket No. RM22-12-000), Registration of Inverter-Based Resources, November 17, 2022.
[13] FERC Order No. 901, Final Rule Reliability Standards to Address Inverter-Based Resources, October 19, 2023.
[14] FERC Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements, July 28, 2023.

Key Finding 4: Texas Interconnection Reliability Performance Improves While Facing New Challenges

Despite reliability challenges posed by integrating variable generation and new technologies, the Texas Interconnection has demonstrated a high level of improvement to reliability by using BESS to support frequency (Figure 6).15 Additionally, the Texas Interconnection showed statistically significant improvement to its misoperation rate in 2023, compared to the prior four years (see Figure 7).[16] The Texas Interconnection experienced relatively normal generation and transmission outages in comparison to prior years.

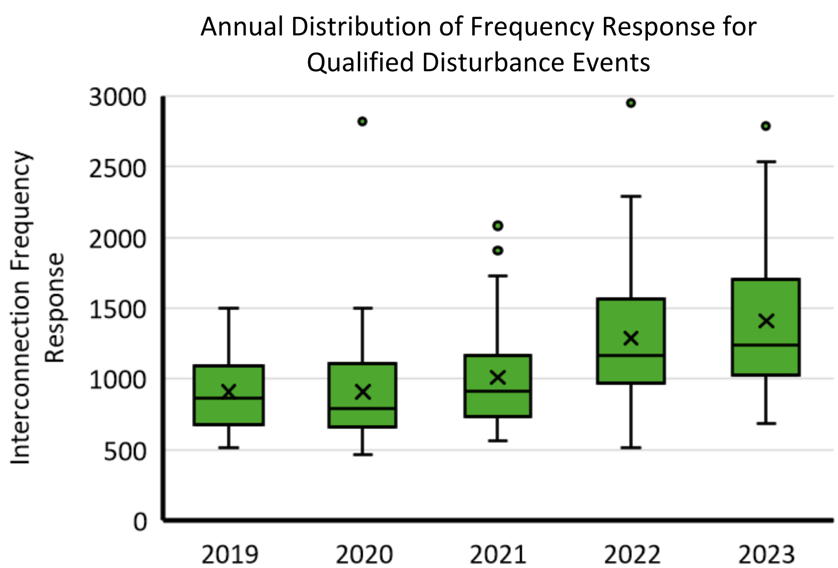

Figure 6: Texas Interconnection Frequency Response (M4) by Operating Year (2019–2023)

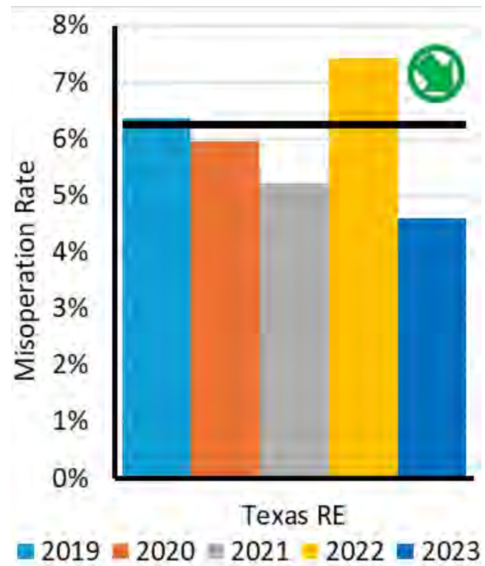

Figure 7: Changes and Trends in the Annual Misoperations Rate

As reported in NERC reliability assessments[17] and the *2023 SOR* report,[18] the Texas Interconnection can no longer meet summer and winter peak demand with only conventional generation and has demonstrated how these challenges can be successfully managed while at the same time encountering new ones. BESS also provided valuable energy and ramping support to help manage the September 6, 2023, energy emergency Level 2 alert that occurred during the rapid down-ramp of solar generation that evening.[19]

Resultant Actions

- Electric Reliability Council of Texas, Inc. (ERCOT) has proposed changes to the ERCOT Nodal Operating Guides to incorporate performance requirements for IBRs. These changes are being reviewed through the ERCOT stakeholder process.

[15] M-4 Interconnection Frequency Response
[16] M-9, Protection System Misoperations Rate
[17] NERC Reliability Assessments
[18] 2023 State of Reliability Report
[19] Electric Reliability Council of Texas filing to the Texas Public Utility Commission on the September 6, 2023, Energy Emergency Level 2 Event.

Acknowledgements

NERC would like to express its appreciation to the many people who provided direct technical support and identified areas for improvement to this document as well as all the people across the industry who work tirelessly to keep the lights on every day.

NERC Industry Group Acknowledgements	
Group	**Officers**
Reliability and Security Technical Committee	Chair: Rich Hydzik, Avista Vice Chair: John Stephens, City Utilities of Springfield
Performance Analysis Subcommittee	RSTC Sponsor: Darryl Lawrence, PA Office of Consumer Advocate Chair: David Penney, Texas RE Vice Chair: Heide Caswell, Oregon Public Utilities Commission
Events Analysis Subcommittee	Chair: Chris Moran, PJM Vice Chair: James Hanson, WECC
Generation Availability Data System User Group	Chair: Danny Small, City Utilities Vice Chair: Ken Sabourin, Sunflower Energy
Electric Gas Working Group	Chair: Mike Knowland, ISO New England, Inc. Vice Chair: Daniel Farmer, Entergy
Misoperations Information Data Analysis System User Group	Chair: Thomas Teafatiller, ReliabilityFirst Vice Chair: Stony Martin, SERC
Transmission Availability Data System User Group	Chair: John Idzior, ReliabilityFirst Vice Chair: Nick DePompei, SERC
Resources Subcommittee	Chair: Greg Park, NWPP RS Vice Chair and NPCC: Bill Henson, ISO-NE
Real-Time Operating Subcommittee	Chair: James Hartmann, Electric Reliability Council of Texas, Inc. Vice Chair: Timothy Beach, California Independent System Operator (RC West)
Reliability Assessment Subcommittee	Chair: Amanda Sargent, WECC Vice Chair: Vacant
System Protection and Control Working Group	Chair: Jefrey Iler, AEP Vice Chair: Bill Crossland, ReliabilityFirst

Exhibit 16

2023 State of Reliability Overview

June 2023

Assessment Overview of 2022 Bulk Power System Performance

2023 SOR Technical Assessment | 2023 SOR Video | 2023 SOR Infographic

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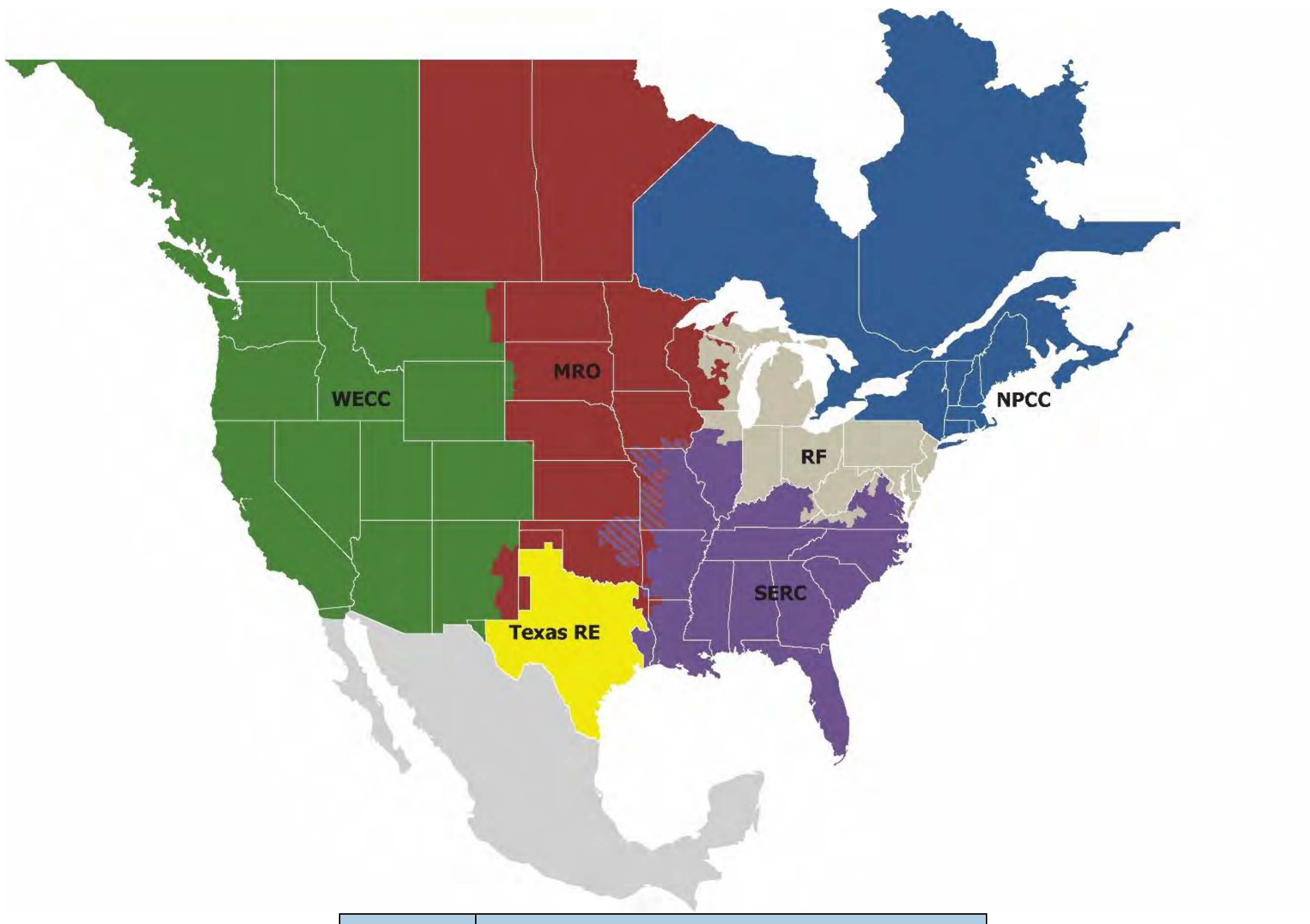

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About This Overview

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Development Process

ERO staff, supported by the Performance Analysis Subcommittee, developed this overview and the corresponding *2023 State of Reliability Technical Assessment* based on an established set of reliability indicators and mandatory information reported by industry to the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), and NERC's annual *Long-Term Reliability Assessment* (LTRA). In addition, voluntary information reported by industry to the Event Analysis Management System (TEAMS), the Electricity Information Sharing and Analysis Center (E-ISAC), and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group is also included.

Considerations

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- Information used in this overview is based on data available Spring 2023. All dates and times shown are in Coordinated Universal Time (UTC).
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[1] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf

2022 Highlights

Based on data and information collected for this *SOR Overview* of BPS reliability performance in 2022, NERC identified the following findings:

- **Key Finding 1: Conventional Generation Reliability**
- **Key Finding 2: Solar PV Inverter Performance during Transmission Faults**
- **Key Finding 3: Security Threats**
- **Key Finding 4: Transmission System Reliability**
- **Misoperations**
- **Expanding Role of Data in Assessing BES Performance**

Overall, the BPS was reliable[2] throughout 2022. However, extreme weather events continue to pose the greatest risk to reliability due to the increase in frequency, footprint, duration, and severity. In 2022, the National Oceanic and Atmospheric Administration identified 18 separate billion-dollar weather-related disasters in the United States, see **Figure 1**. Additionally, one such disaster occurred in Canada.[3] Thirteen of these events affected the performance observed on the days with the most significant reliability impacts on generation, transmission, and loss of customer load (as measured by the severity risk index[4]).

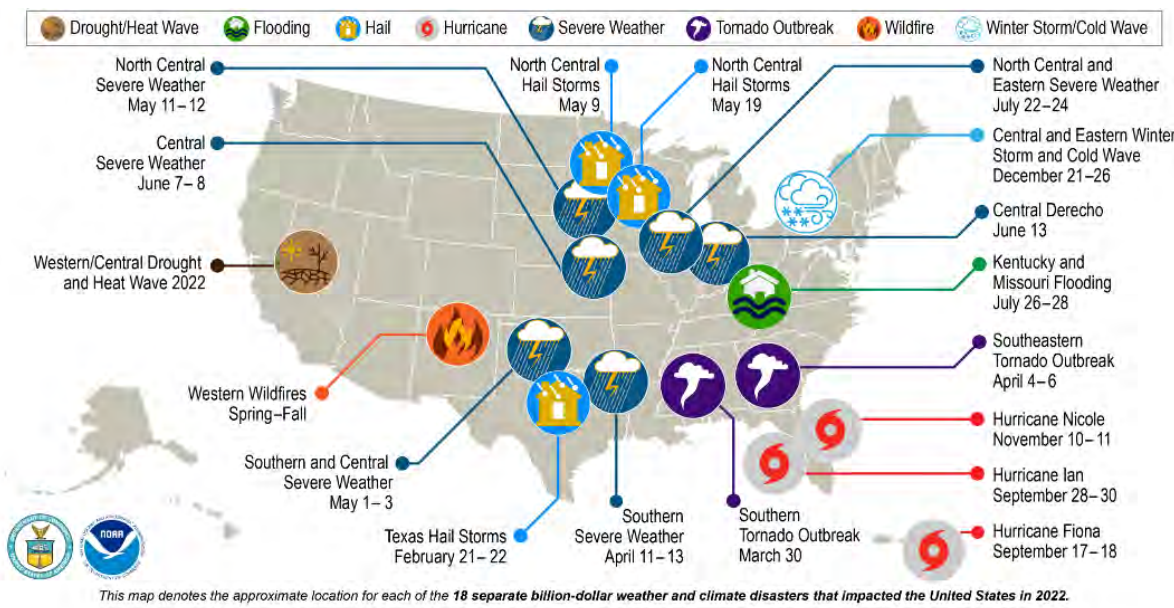

Figure 1: 2022 U.S. Billion Dollar Weather Related Disasters[5]

Notably, the most significant reliability event of the year was Winter Storm Elliot, which swept over the majority of the Central and Eastern United States in December 2022. The severity of this event led the Federal Energy Regulatory Commission (FERC) and NERC to form a joint inquiry with Regional Entities that is currently underway. Accordingly,

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[2] Learn About NERC provides background information about NERC, the definition of reliability, and understanding the grid.
[3] Severe weather in Canada caused $3.1 billion in insured damages in 2022.
[4] The Severity Risk Index is a daily metric where transmission, generation, and load loss events aggregate into a single value that indicates the performance of the BES: https://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/SRI_Enhancements_October_2020.pdf
[5] *National Oceanic and Atmospheric Administration National Centers for Environmental Information U.S. Billion-Dollar Weather and Climate Disasters* (2023): https://www.ncei.noaa.gov/access/billions/, DOI: 10.25921/stkw-7w73

this overview does not discuss the actions resulting from this event that will be incorporated in the inquiry findings later this year.

Figure 2 highlights a few key numbers and facts about the North American BPS.

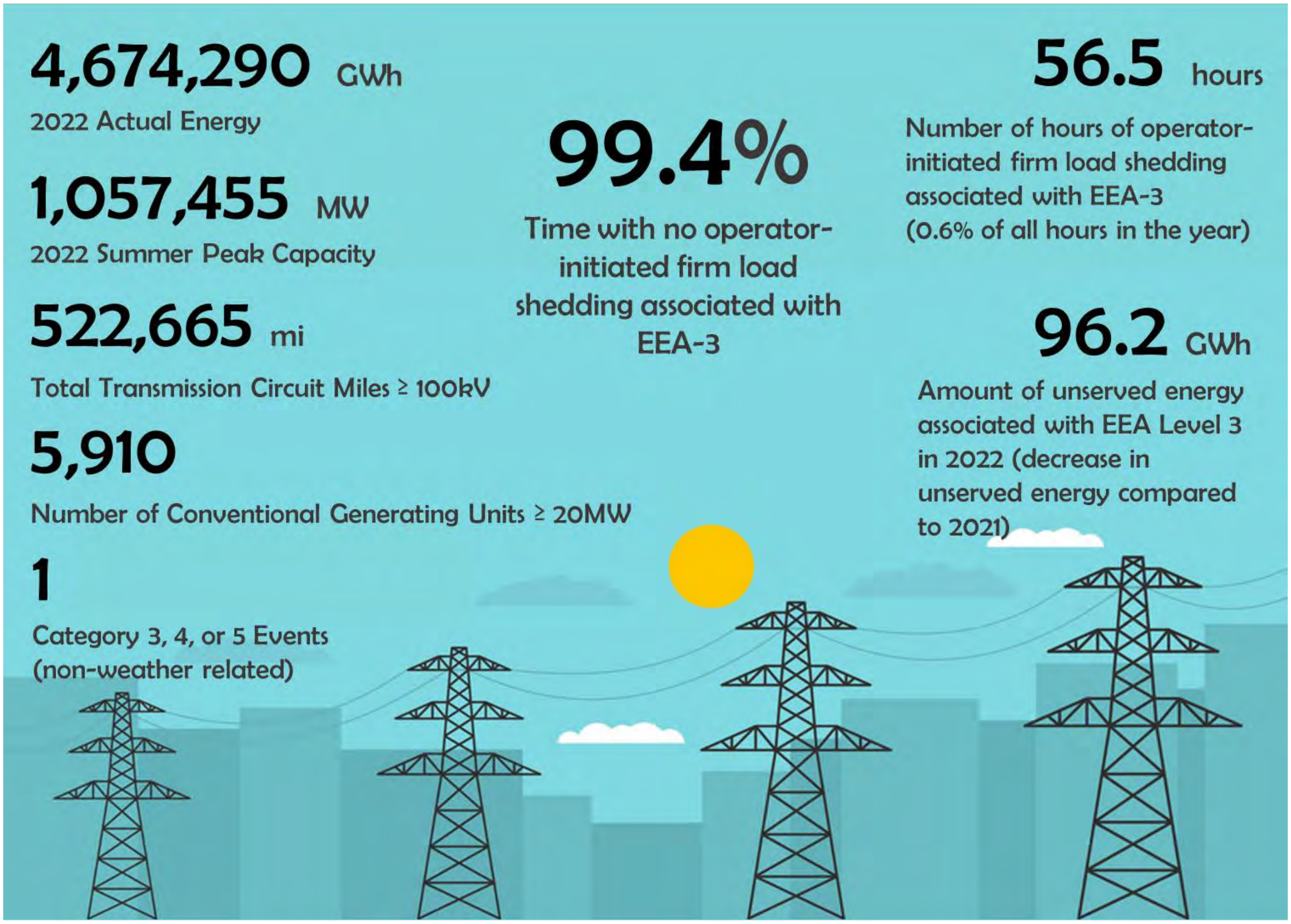

Figure 2: 2022 BPS Inventory and Performance Statistics

Key Finding 1: Conventional Generation Reliability

The reliability of conventional generation is significantly challenged by more frequent extreme weather, high-demand conditions, and a changing resource mix, resulting in higher overall outage rates and surpassing transmission in their contribution to major load loss events.

In 2022, conventional generation experienced its highest level of unavailability (8.5%) overall since NERC began gathering GADS data in 2013 as measured by the weighted equivalent forced outage rate (WEFOR). **Figure 3** shows consistently increasing outage rates for coal over the observed five years, correlating with higher numbers of startups and maintenance outages. **Figure 3** also shows that the unavailability of the gas-fired generation fleet in recent years has been consistently higher during the winter months. These are the two primary factors to conventional generation surpassing transmission in contributing to major load loss events. There are no apparent trends in the unavailability of the other forms of generation.

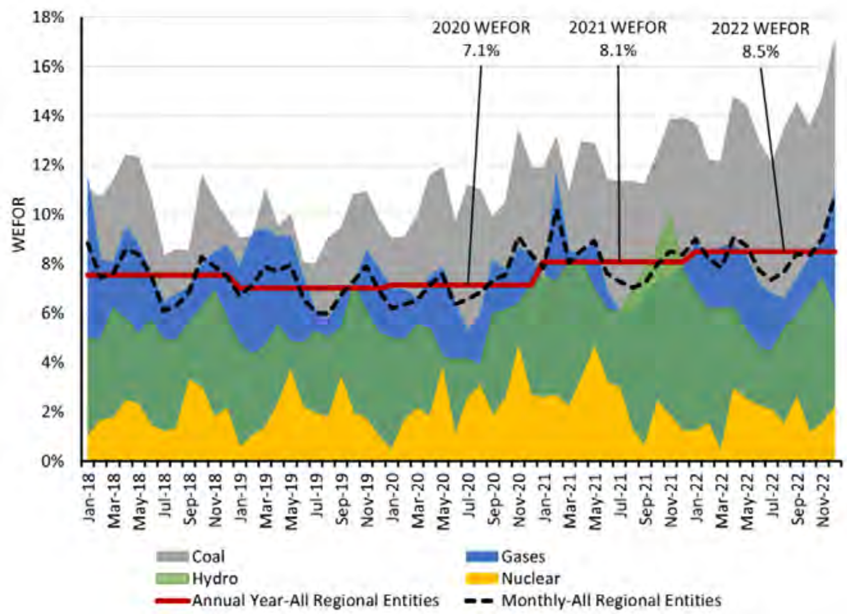

Figure 3: 2022 Monthly Weighted Equivalent Forced Outage Rate by Fuel Type

Inverter-based resource (IBR) capacity has increased while conventional generation capacity has decreased in both the Texas and Western Interconnections (as seen in **Figure 4**). The Texas Interconnection can no longer meet peak demands with only conventional generation. The variability in IBRs also places increased operational demands on the now smaller fleet of conventional generation.

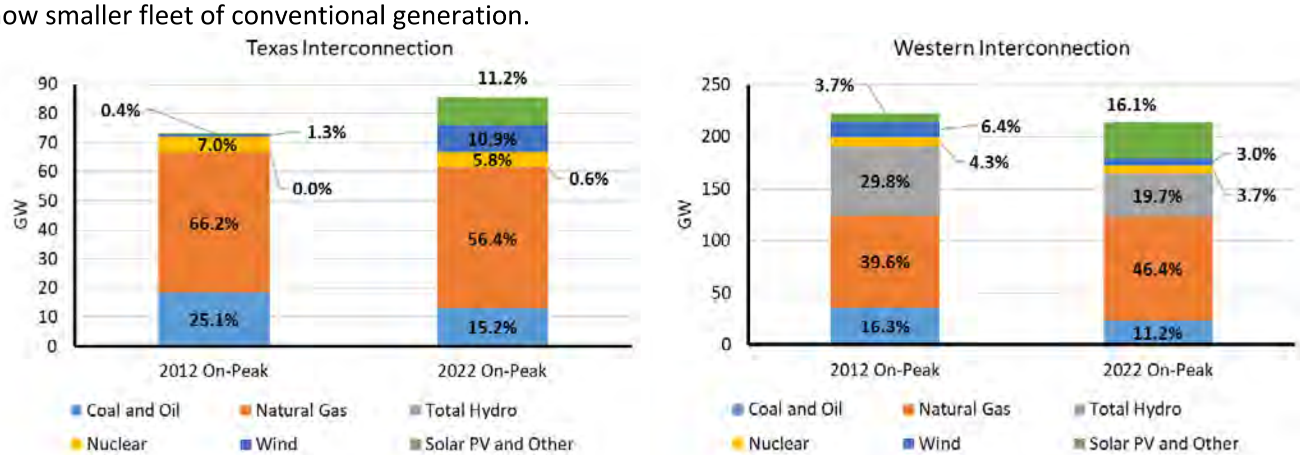

Figure 4: Texas Interconnection and Western Interconnection 2012 and 2022 On-Peak Capacity Resource Mix

For the second year in a row, high temperatures have created reliability challenges, including a notable near-miss event. In mid-June, sustained high temperatures across North America caused a large number of generator outages and a large amount of load loss. In the Western Interconnection, the multi-year drought reduced water levels in the Hoover and Glen Canyon dam reservoirs, which represent a combined capacity of more than 3,300 MW, to the lowest levels since first filled. Continued drought conditions would lead to an inability of these (and other) dams to produce power, introducing major operational challenges during high demand periods. In September, an Interconnection-wide heat wave set record high temperatures in more than 1,000 cities, leading to a record peak demand of 167,530 MW for the Western Interconnection. Seven Level 3[6] energy emergency alerts (EEA), energy conservation, demand-side management, and other measures enabled Western Interconnection Balancing Authorities to operate through the period without having to shed firm load.

Resultant Actions

- NERC issued a Level 3 essential action alert[7] in May 2023: *Essential Actions to Industry - Cold Weather Preparations for Extreme Weather Events*.[8]
- Three standards were revised as a result of the 2019 cold weather event that became effective April 1, 2022;[9] additional standards revisions resulting from the 2021 cold weather event are ongoing.[10]
- NERC published three lessons learned[11] documents.
- *FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States.*[12]
- FERC, NERC, and Regional Entity joint report on the 2022 Winter Storm Elliott is expected in late 2023.
- NERC hosted its annual Preparation for Severe Cold Weather webinar.
- Reliability assessment data requests were expanded to further measure preparedness during cold weather events.
- The WECC Reliability Risk Committee is identifying specific risk areas under "Extreme Natural Events" that pose unique risks to the Western Interconnection and how industry can best address them.
- NERC GADS Section 1600 data request revisions,[13] which include reporting of specific environmental contributing factors for outages and event performance for wind and solar photovoltaic (PV) plants, become effective January 1, 2024.

[6] https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf
[7] https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx
[8] https://www.nerc.com/news/Pages/NERC-Releases-Essential-Action-Alert-Focused-on-Cold-Weather-Preparations.aspx
[9] https://www.nerc.com/pa/Stand/Pages/Project%202019-06%20Cold%20Weather.aspx
[10] https://www.nerc.com/pa/Stand/Pages/Project-2021-07-ExtremeColdWeather.aspx
[11] LL20220301 "Managing UFLS Obligations and Service to Critical Loads during an Energy Emergency
LL20221201 "Air Breaker Cold Weather Operations
LL20230401 "Combustion Turbine Anti-Icing Control Strategy
[12] FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States
[13] https://www.nerc.com/pa/RAPA/PA/Pages/Section1600DataRequests.aspx

Key Finding 2: Solar PV Inverter Performance during Transmission Faults

To continue benefiting from the rapid expansion of inverter-based resources, their dynamic performance during system events must improve.

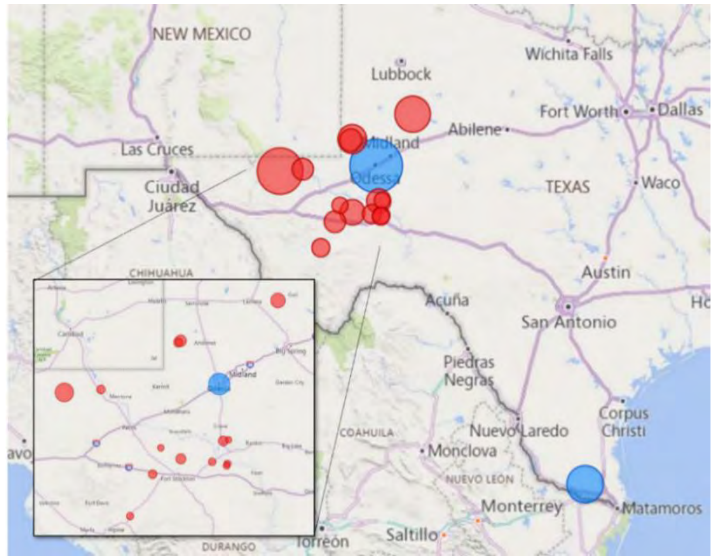

Figure 5: 2022 Impact of Odessa Disturbance

On June 4, 2022, a failed surge arrestor caused the loss of 333 MW of synchronous generation, leading to an erroneous loss of an additional 511 MW of synchronous generation and an unexpected loss of 1,700 MW of solar PV generation in the Texas Interconnection titled the Odessa Disturbance.[14] **Figure 5** shows the locations of the solar PV plants (**red**), the MW (by bubble size), and the conventional generation lost (**blue**). The total generation lost exceeded the most severe single contingency and nearly exceeded the Texas Interconnection resource loss protection criteria, the design threshold that is used to establish the requirements for frequency recovery in the Texas Interconnection.

Notably, the event was nearly identical to one that took place at the same location just over a year ago.[15] It is consistent with recent Western Interconnection events that have also shown that newly built solar PV and battery storage resources continue to be commissioned with known performance issues; these issues have long been highlighted in disturbance reports and NERC alerts dating back to 2016.[16]

Resultant Actions

- FERC Notice of Proposed Rulemaking issued November 17, 2022,[17] was released to address concerns regarding reliability impacts on IBRs.
- NERC Level 2 alert[18] was issued March 14, 2023, on IBR issues.[19]
- Reliability Standard[20] modifications are in progress for PRC-024, MOD-025, MOD-026, MOD-027, FAC-001, FAC-002, PRC-002, PRC-019, and EOP-004.
- NERC published multiple guidelines and resources.[21]
- Immediate industry action is necessary to implement published guidelines and ensure reliable operation of the BPS with the increasing penetration of IBRs.
- IBR modeling requirements need significant improvement to ensure that high-quality, accurate models are used during reliability studies so performance issues can be identified before they occur during real-time operations.

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[14] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20(1).pdf
[15] https://www.nerc.com/pa/rrm/ea/Pages/May-June-2021-Odessa-Disturbance.aspx
[16]
https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf
[17] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221117-3114&optimized=false
[18] https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx
[19] https://www.nerc.com/pa/rrm/bpsa/Alerts DL/NERC Alert R-2023-03-14-01 Level 2 - Inverter-Based Resource Performance Issues.pdf
[20] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx
[21] https://www.nerc.com/pa/Documents/IBR_Quick Reference Guide.pdf

Key Finding 3: Security Threats

Physical and cyber security attacks are increasing, reinforcing the need for further development and adaptation of standards and guidelines.

Physical and cyber security are essential to BPS reliability, and security is becoming increasingly important in the ongoing grid transformation. The growing attack surfaces that result from the increasing penetration of distributed energy resources call for ongoing development and adaptation of cyber and physical security standards and guidelines to keep up with the ever-changing threat landscape. Furthermore, cyber-informed planning should include designs and be considered when planning and integrating the technologies into the grid to strengthen the cyber robustness.[22]

Hostile nation-states persist in targeting North American critical infrastructure and are constantly evolving their methods to compromise the grid's reliability, resilience, and security. Domestic extremists have demonstrated the intent to attack the electricity infrastructure and take violent action against grid assets. **Figure 6** provides the breakdown of Level 2 and 3 incident types.[23]

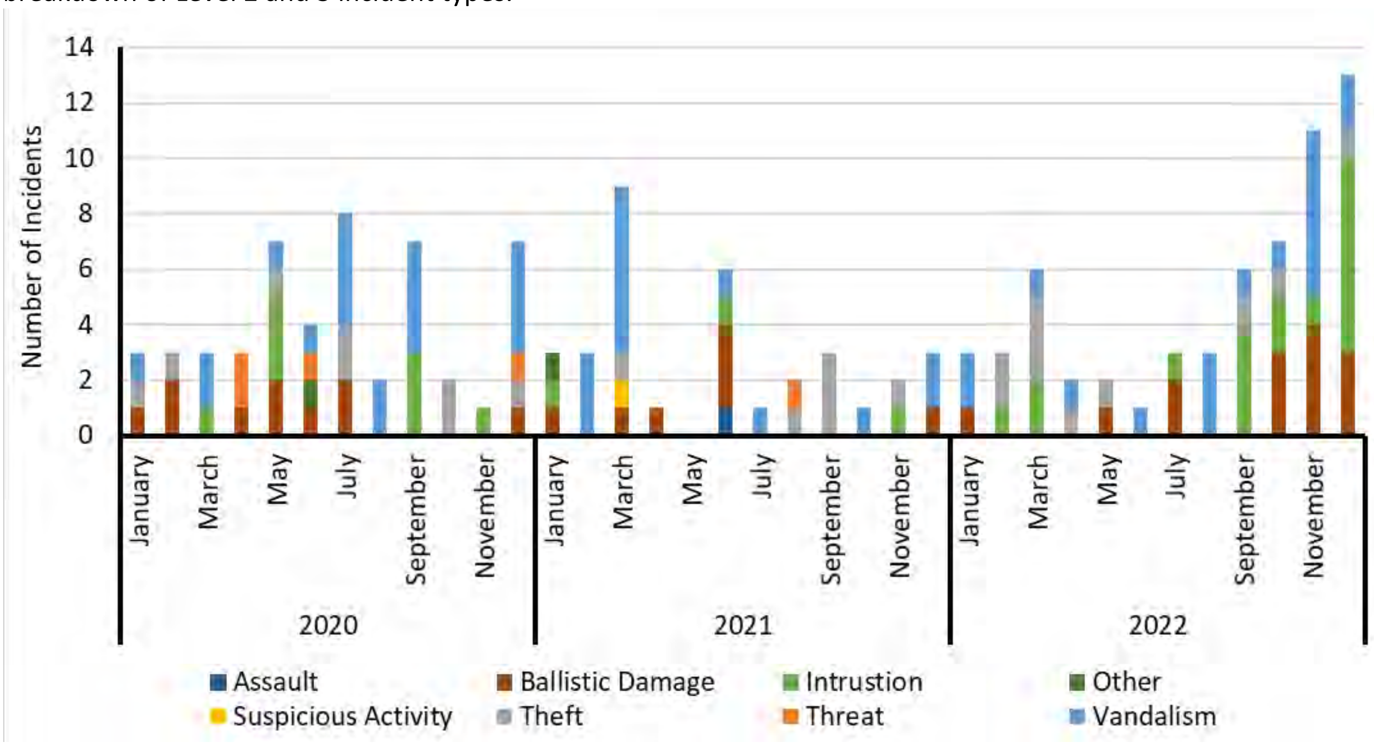

Figure 6: Level 2 and 3 Physical Incidents by Type for 2020–2022

Resultant Actions

- The E-ISAC continuously gathers and distributes industry threat intelligence and works with government and industry partners to mitigate risks and provide guidance as threats arise.
- Through coordination and collaboration with the ERO Enterprise and industry stakeholders, NERC will provide insightful white paper guidance, implement robust security strategies, and continue to refine and adapt critical standards about cyber-informed engineering design to ensure a reliable and secure BPS. These efforts will enable industry to be better positioned against physical and cyber threats now and in the future.

[22] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/ERO_Enterprise_Whitepaper_Cyber_Planning_2023.pdf

[23] Incident types: Level 1: Criminal activity with no impact to the grid. Level 2: Physical security incident with any impact to the grid. Level 3: Physical security incident with direct and significant impact to the grid.

Key Finding 4: Transmission System Reliability

The Bulk Electric System (BES) transmission system continues to demonstrate significantly improved reliability for the fifth year in a row.

Figure 7 shows that the reliability of the transmission system, as measured by overall transmission outage severity (TOS), has improved continuously over the past five years. Figure 8 shows that the unavailability of ac transmission circuits in 2022 was lower than the average over the prior four years. Hard to predict high-wind and lightning systems continue to be the most regular notable challenges to the system.

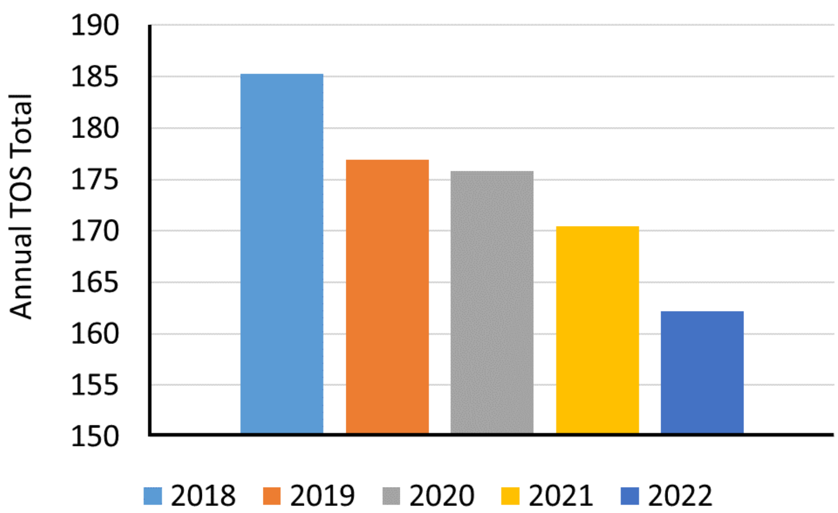

Figure 7: TOS Annual Comparison

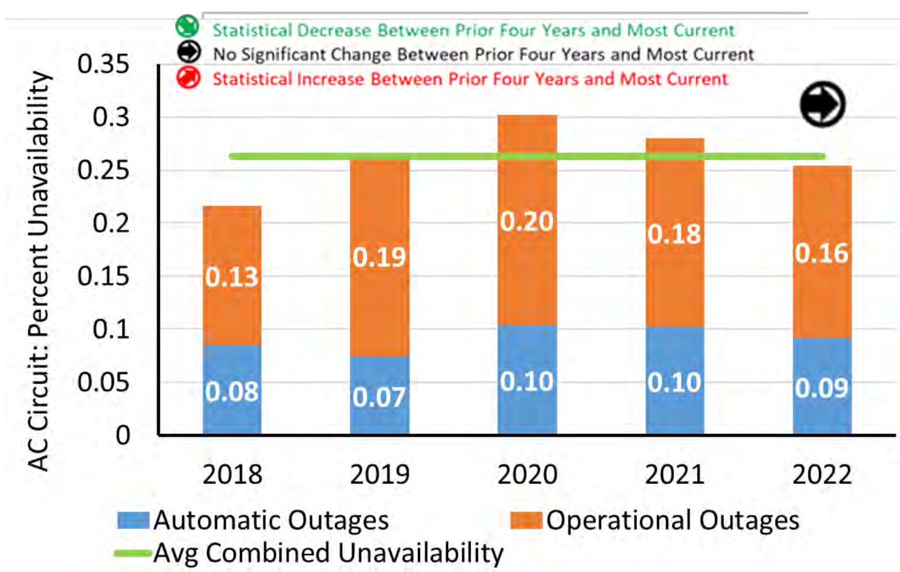

Figure 8: AC Circuit Unavailability

Transmission System Response to Hurricane Ian

Hurricane Ian began as a Category 5 hurricane that crossed Central Florida then made a secondary landfall on the East Coast of the United States two days later. **Figure 9** shows a timeline of the transmission outages and restorations during the event. The Outages Curve (**orange**) depicts the cumulative number of elements out at any given time during the event, while the Restores Curve (**green**) depicts the cumulative number of elements restored. The Simultaneous Elements Out Curve (**blue**) combines the degradation and recovery phases of the event, depicting the number of elements out simultaneously at any given time. The effective restoration (95%) was completed within 3.8 days compared to an average hurricane restoration time of 8.6 days from 2017–2022.

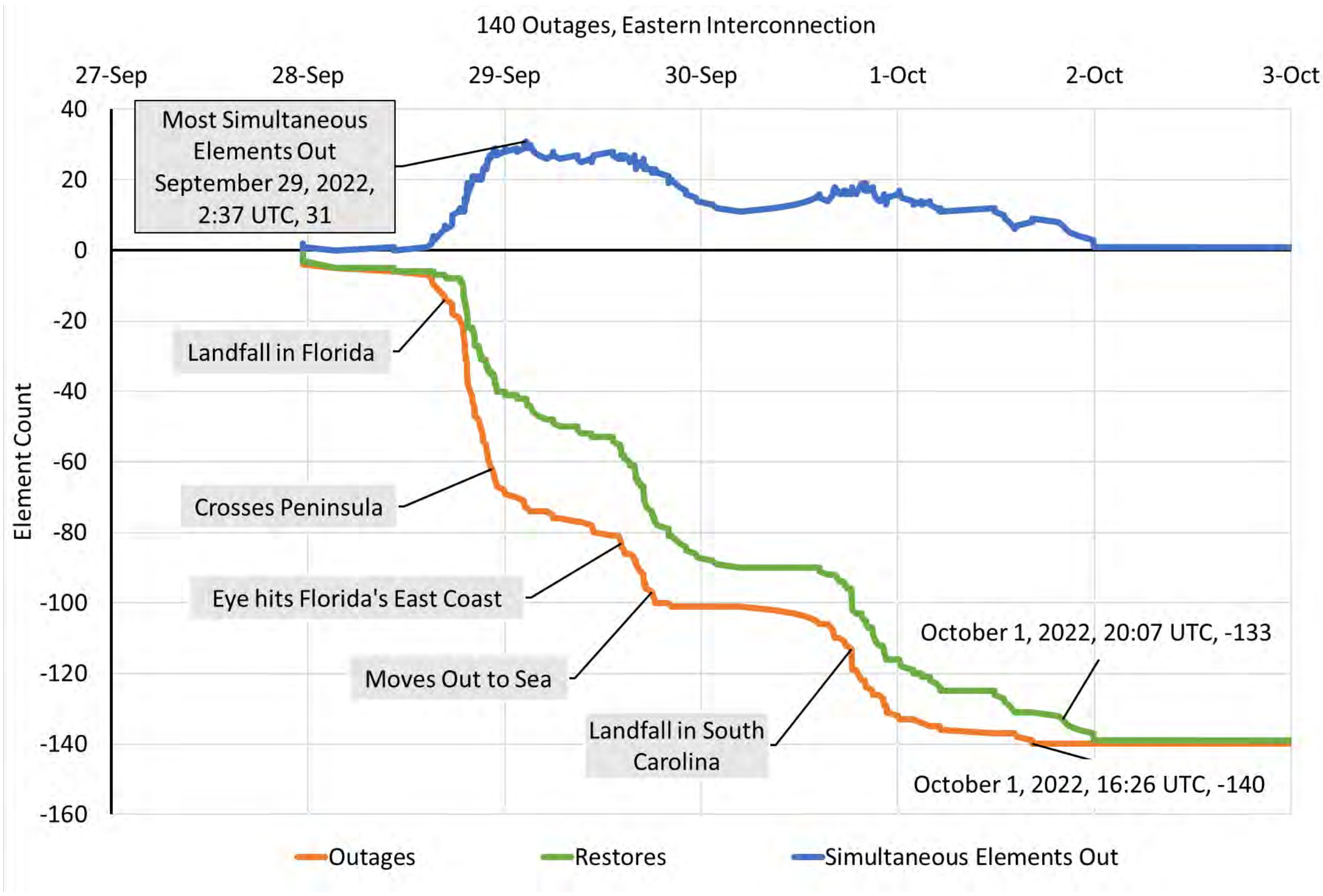

Figure 9: Hurricane Ian Restoration Curves

Misoperations

Protection system misoperations continue to improve with a downward trend in counts, rates, and impact metrics.

Analysis of misoperations indicates a continuing downward trend in misoperation counts, rates, and impact metrics. When comparing 2022 to the prior four years, the misoperations rate statistically significantly decreased in the ReliabilityFirst footprint and overall (see **Figure 10**) but increased in Texas RE. Analysis indicates that this misoperations rate increase is due to a decrease in protection system operations that is not reflected in the misoperations count; this is also supported by a slight increase in misoperations caused by incorrect settings, and relay and communication failures. This aligns with the overall trend that protection system operations counts have only decreased by 10% since 2018 while misoperations have decreased from 1,536 in 2018 to 1,170 in 2022. New analysis, which is detailed in the *2023 SOR Technical Assessment*, approximates the impact of misoperations on the BES and indicates no increase in overall severity. The ERO is continuing to develop analyses to provide comprehensive measures of protection systems while keeping industry informed through a variety of outreach opportunities.

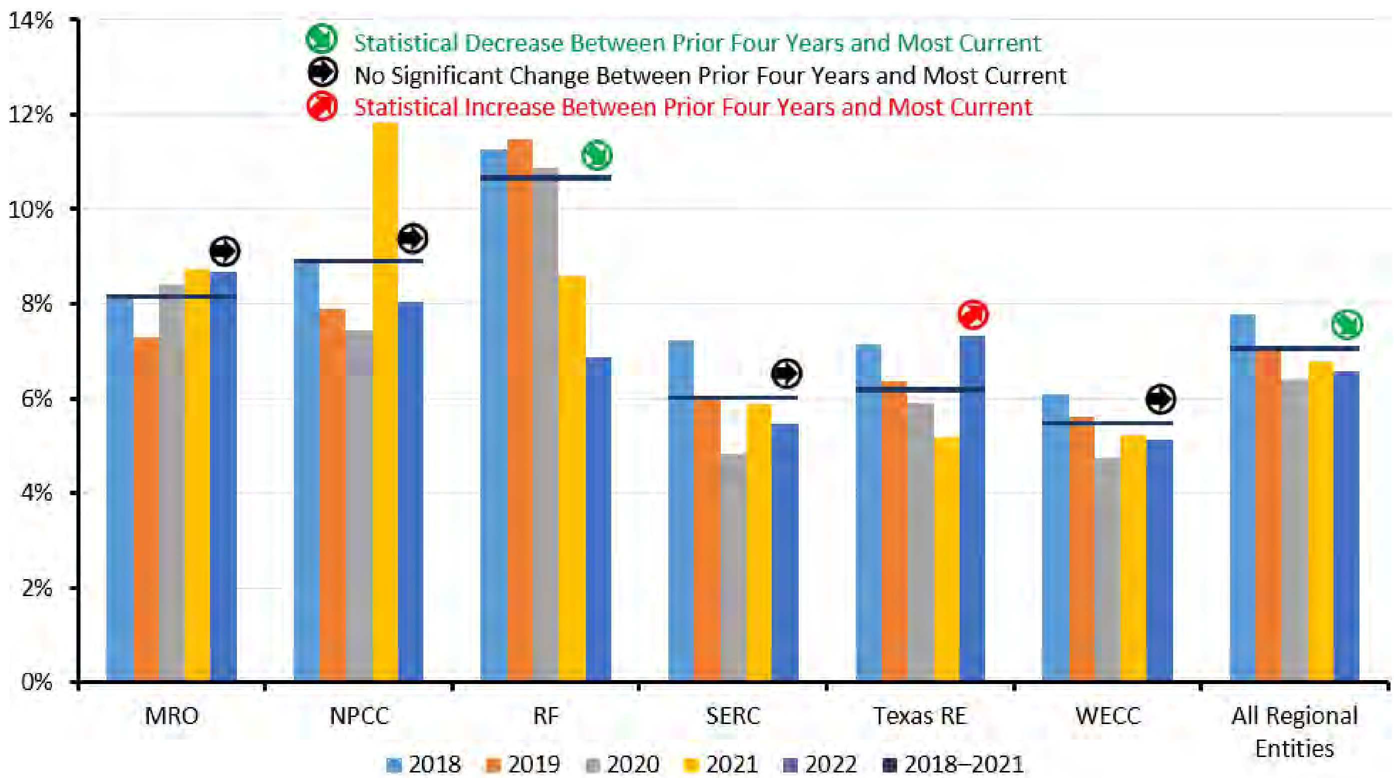

Figure 10: Changes and Trends in the Annual Misoperations Rate by Regional Entity

Expanding Role of Data in Assessing BES Performance

In recent years, the limited access to data necessary to conduct deeper analysis of current BES challenges, such as extreme weather, have become increasingly evident.

Alignment of data sources, clarity of data granularity, timeliness, modeling capabilities, precision with definitions, and the ability to correlate data across and within datasets has become increasingly critical. Revisions to GADS Section 1600 that become effective in 2024 include additional wind and solar PV data as well as information to clearly indicate whether external operating conditions have contributed to a reported outage. NERC is also reviewing Section 1600 data requests currently in effect to align them with current and future analytical needs. Areas under consideration include BES load loss information, IBR modeling capabilities, modeling data accuracy, transmission information to identify relation to weather events, daily peak generation capacity or demand information, and more quantifiable information regarding the severity of transmission outages and protection system misoperations.

Acknowledgements

NERC would like to express its appreciation to all the people across the industry who work tirelessly to keep the lights on each and every day in addition to the many individuals who provided technical support and identified areas for improvement in this report.

NERC Industry Group Acknowledgements	
Group	**Officers**
Reliability and Security Technical Committee	Chair: Greg Ford, Georgia System Operations Corporation Vice Chair: Rich Hydzik, Avista
Performance Analysis Subcommittee	RSTC Sponsor: Darryl Lawrence, PA Office of Consumer Advocate Chair: David Penney, Texas RE Vice Chair: Heide Caswell, Oregon Public Utilities Commission
Event Analysis Subcommittee	Chair: Chris Moran, PJM Vice Chair: James Hanson, WECC
Generation Availability Data System User Group	Chair: Leeth DePriest, Southern Company Vice Chair: Danny Small, City Utilities
Misoperations Information Data Analysis System User Group	Chair: Thomas Teafatiller, ReliabilityFirst Vice Chair: Stony Martin, SERC
Transmission Availability Data System User Group	Chair: John Idzior, ReliabilityFirst Vice Chair: Nick DePompei, SERC
Resources Subcommittee	Chair: Greg Park, NWPP RS Vice Chair & NPCC: Bill Henson, ISO-NE
Real-Time Operating Subcommittee	Chair: James Hartmann, Electric Reliability Council of Texas, Inc. Vice Chair: Timothy Beach, California Independent System Operator (RC West)
Reliability Assessment Subcommittee	Chair: Andreas Klaube, NPCC Vice Chair: Amanda Sargent, WECC
System Protection and Control Working Group	Chair: Jeffrey Iler, AEP Vice Chair: Bill Crossland, ReliabilityFirst

Exhibit 17

Alternative Arrangements Pursuant to 40 CFR Section 1506.11 – Emergencies

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
1. Release of HUD Section 108 loan guarantee funds to initiate land acquisition, relocation, site clearing and demolition activities.	Michigan governor declared City of Detroit to be in a state of emergency due to economic crisis. GM threatened to build a new plant outside the city unless a cleared site was delivered by May 1981.	City of Detroit, Michigan, under Section 104(h) of Community Development and Housing Act of 1974.	9/19/1980 Request: 9/22/1980 CEQ response: 9/24/1980	CEQ concurred in alternative arrangements proffered by HUD and the City which included substantial mitigation and notification efforts, and no demolition prior to discussion with Advisory Council on Historic Preservation. Upheld in Crosby v. Young, 512 F. Supp. 1363 (E.D. Mich. 1981).
2. Construct emergency regulating pond to stop sewage flow from Tijuana, Mexico, into the U.S.	Uncontrolled sewage flowing into U.S. would pose health risk and foul beaches.	International Boundary and Water Commission	3/8/1983	CEQ approved upon receipt of an environmental memorandum; preparation of EA followed.
3. Established boundary for an immediate separation between adjacent stone crab and shrimp fisheries.	Conflict escalated into physical violence between the two fisheries.	DOC / NOAA	3/9/1983	CEQ concurred in establishment of boundary, noting that fishery season would terminate shortly (and boundary issue would be fully addressed in the two 1983-84 fishery management plans.
4. Spray for mosquitoes with pesticides.	Outbreak of encephalitis in Yuma Proving Grounds, Arizona.	DOD /US Army	8/8/1983	CEQ approved arrangement to meet clear and present threat to human and animal health, noting that an EA or EIS might be necessary if long-term spraying were required.
5. Published an emergency temporary standard on asbestos.	Remove harmful asbestos materials.	DOL / OSHA	12/16/1983	CEQ agreed to publication of temporary asbestos standard on condition that OSHA assessment would be done on environmental effects prior to permanent standard hearings.
6. Aerial spraying of malathion pesticides in Idaho.	Infestation of migratory grasshoppers on Idaho cropland.	USDA / APHIS	8/3/1984	APHIS notified CEQ of the action, advising that 1979 Programmatic EIS found no adverse environmental effects.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
7. Stabilize the structural elements of a historic building prior to completion of the EIS process on the renovation.	Prevent the collapse of structure and exposure to hazardous asbestos.	Albany, NY Urban Renewal Agency under the Urban Development Action Grant program.	10/16/1984	CEQ agreed with the action considering that the asbestos removal qualified as an emergency circumstance and that stabilization would not cause environmental harm.
8. Clean up herbicide-contaminated material prior to the preparation of environmental documentation.	Herbicide-contaminated materials discovered at Fort A.P. Hill, Virginia (site of the 1981 Boy Scout Jamboree).	DOD /US Army	11/21/1984	CEQ agreed that environmental documents would be prepared concurrently with testing and clean- up at the site.
9. Issue a right-of way grant and allow the State of Utah to begin construction of the Great Salt Lake West Desert pumping project prior to the projected filing of the FEIS with EPA in July 1986.	Rising lake levels threatened extensive damage to surrounding industries, wildlife habitats, recreation areas, transportation systems, and personal and private property.	DOI / BLM	2/27/1985	CEQ approved the project in May 1986 (after Utah legislature authorized construction funds), provided that BLM complete the NEPA process, discussing the environmental impacts due to changes from the original EIS and that the state mitigate impacts as agreed to through the EIS process.
10. Issue a permit, based on a change to FWS policy, to capture the six remaining California condors and remove them from the wild.	Precipitous decline of species suggested that extinction was likely without enhancement of propagation.	DOI / FWS	12/20/1985	CEQ agreed to issuance of permit, noting 9/85 EA and 10/85 FONSI and that efforts were directed toward reentry of species in the wild. Upheld in National Audubon Society v. Hester, 801 F.2d 405 (D.C. Cir. 1986).

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
11. Destroy 1.3 million steelhead trout at Coleman National Fish Hatchery, California.	Spread of incurable whirling disease, classified as emergency by FWS.	DOI / FWS	1/31/1986	CEQ approved on basis of January 1986 EA.
12. Aerial spraying of pesticide malathion prior to signing ROD.	Grasshopper infestation on rangeland in Arizona.	USDA / APHIS	4/25/1986	CEQ approved action on condition that it was limited to acreage originally specified in request.
13. Destroy 5 million juvenile upright bright fall Chinook salmon at Little White Salmon National Fish Hatchery, WA.	Outbreak of untreatable viral Infectious Hematopoietic Necrosis (IHN).	DOI / FWS	5/19/1987	CEQ approved destruction, noting that the EA evaluated impacts and alternatives to proposed action.
14. Remove unexploded ordnance near Martha's Vineyard in MA.	Ordnance exposed by natural wave process posed hazard to beach users unaware of it.	DOD / US Army	8/29/1988	Consultation was concurrent with the removal action and prior to completion of an EA.
15. License a hydroelectric facility at Milner Dam in Idaho.	License issuance to allow money needed for immediate repairs to prevent dam failure due to seepage or earthquake.	FERC	10/25/1988	CEQ approved based on FERC's commitment to impose license conditions to mitigate any adverse impacts.
16. Destroy 3.42 million Pacific salmon and steelhead eggs and fish at Makah National Fish Hatchery, Washington.	Spread of untreatable virus: Viral Hemorrhagic Septicemia (VHS).	DOI / FWS	3/4/1989	CEQ approved after review of February 1989 EA.
17. Lower the water level behind Clear Creek Dam and Reservoir in Yakima, WA, to 2970 feet.	Potential dam failure which threatened both loss of life and property.	DOI / BLM	1/3/1990	CEQ approved with understanding that repairs or reconstruction thereafter would be conducted in compliance with NEPA.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
18. Aerial spraying of pesticide malathion over residential areas in Los Angeles, CA.	Threatened outbreak of Mediterranean fruit fly infestation resulting in economic losses of over $800 million to CA agricultural industry.	USDA / APHIS	1/19/1990	CEQ approved with 5 conditions: strict adherence to EPA quarantine exemption on malathion; vigorously pursue the NEPA process; employ monitoring program; provide monthly status reports to CEQ; and publish notices in affected counties.
19. Issue right-of-way for construction of Upper Flamingo Wash Detention Basin in Las Vegas, NV.	Frequent flooding that previously resulted in loss of life and millions dollars in damages.	DOI / BLM	12/4/1990	CEQ concurred with the understanding BLM would complete the NEPA process for the remainder of the project.
20. Allow night flights into and an increase in the overall number of flights from Westover Air Force Base in Massachusetts.	In response to hostilities in Kuwait, troops and military supplies had to be transported for use in Persian Gulf military operations (Operation Desert Shield) and the Air Force needed to change C-5A flight operations from those predicted in an EIS for the stationing of a unit of Air Force Reserve C-5A aircraft at Westover.	DOD / Air Force	11/21/1990 CEQ granted alternative arrangements 3/19/1991	The alternative arrangements required DOD/Air Force to immediately to implement five conditions: develop and complete, within 30 days, an EA documenting the environmental impacts of operations which exceeded the nature and number of flights occurring prior to Operation Desert Shield; provide for distribution, notice of availability, and a 30-day public comment period; provide Air Force responses to substantive comments; and continue efforts to remain alert to opportunities to lessen nighttime use over Westover. The Air Force committed to monitoring and publishing the results, and to preparing a supplemental EIS for the beddown of C-5A aircraft at Westover. Upheld in Valley Citizens for a Safe Environment v. Vest et al., (D. Mass. May 6, 1991) (WL330963 D. Mass., 1991).
21. Test aerial deactivation of land mine from the air at Tonopah Test Range in Nevada.	Preparation for war in Persian Gulf (Operation Desert Shield).	DOD / Air Force	1/16/1991	CEQ agreed to the testing considering the relatively short time needed for testing aerial deactivation of land mines (approximately 2 days), the military action in the Persian Gulf (Operation Desert Storm) and the service's expeditious consultation with DOI/ U.S. Fish and Wildlife Service and other government agencies with relevant expertise. Testing involved the use of fuel air explosives to clear buried land mines over a large area at the Department of Energy's Tonopah Test Range.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
22. Fund the Idaho Fish & Game Dept. and the Shoshone-Bannock tribe proposal to save the snake river Sockeye salmon.	Decline in salmon population. Migration of this sockeye salmon run had fallen to 4 adults in 1988, 1 adult in 1989 and no adults in 1990.	Bonneville Power Administration	5/1/1991	CEQ agreed to preparation of a special EA and conferencing with NMFS under ESA. CEQ participated in a conference call with representatives of 12 organizations to discuss issues of concern.
23. Drawdown of Par Pond, Savannah River Site.	Inspection of dam revealed depression in earth dam. Emergency drawdown to prevent possible life threatening failure of the dam and spread of sediment and contaminant.	DOE	7/9/1991	CEQ requested a special environmental analysis of the drawdown, repair and refilling of the Par Pond including discussion of mitigation measures. DOE entertained additional mitigation measures after public comment.
24. Allow the City of Portland, Oregon to pump down Bull Run Lake potentially reducing its volume down to 17 ft below normal minimal level.	City of Portland, Oregon, requested pumping additional water from Bull Run to meet emergency water needs of the City.	USDA / Forest Service	9/3/1992	CEQ agreed to allow the City to pump water from Bull Run Lake on condition that the City conduct an EA on the emergency action (distinguished from long-term use NEPA analysis for 20-year permit) as soon as possible. The alternative arrangements required the EA to: address the alternatives considered and their estimated impacts; explain the emergency conditions that support use of 40 CFR 1506.11 and the relationship of the EA to the ongoing long-term use analysis; discuss the limits of knowledge and the City's proposal for data gathering, monitoring and mitigation; and document whether the analysis supports a FONSI and, if not, identify requisite steps forward.
25. Reduce the bird-aircraft strike hazard at the JFK airport prior to APHIS completing a programmatic EIS for its gull-control program.	Severe bird-aircraft hazard conditions at the JFK airport prompted FAA to issue an emergency advisory.	USDA / APHIS	5/7/1993	CEQ issued recommendations regarding immediate actions, the programmatic EIS, and the ultimate decisions. These included: the definition of an acceptable risk, compliance by Secretaries with 16 U.S.C. §460; abstinence by FWS from processing permits under a categorical exclusion; the development of a program to plant and maintain tall grasses and wildflowers, and cooperation amongst Port authorities and FWS in preparing the programmatic EIS.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
26. Receive 144 spent fuel element from Belgium nuclear power plant prior to completing NEPA process.	Belgium nuclear reactor spent fuel element storage was filled to capacity. If the US did not accept the spent fuel elements, the spent fuel had the potential to be used for nuclear weapon production.	DOE	October 1993	Based on discussions with the Department of State, CEQ approved DOE proposal regarding alternative NEPA arrangements. However, Belgium refused the US offer to accept the fuel elements.
27. Block off streets around the White House complex to vehicular traffic.	Security was inadequate to protect the President, First Family and the White House complex.	Department of the Treasury	5/20-21/1995	CEQ concurred with the Department of the Treasury that an emergency situation existed that required immediate action. An EA was prepared after closure.
28. Form spur roads by blading old fire roads and fuel breaks. The total acreage disturbed by the proposed emergency measures constitutes no more than 2.5 acres of land in the Otay WSA. The roads would be closed to public access.	Sudden and dramatic increase in wildfires caused the County of San Diego to declare a state of emergency. Threats to human life and endangered and plant life were identified.	DOI / BLM	6/19/1996	CEQ concurred with BLM proposal to permit the State of California to begin construction of the proposed spur roads and heliports. Alternative arrangements included: FWS onsite review for heliports; BLM consulting FWS if the location of the proposed road or heliports changed; and a BLM archaeologist onsite during construction. Finally, the agency would use normal NEPA process for rehabilitation of disturbed areas after the emergency.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
29. Trench and terrace slopes that lost nearly all vegetation in a fire.	Fire burned 15,000 acres of federal, state and private land near Boise, Idaho. Conditions conductive to flooding, mudslides, and debris flows threatened human life and property, water quality and soil productivity.	DO I / BLM and USDA / Forest Service	9/19/1996	CEQ approved alternative arrangements that included: distributing additional copies of the interagency report to interested parties; implementing use of vegetative screening; developing monitoring plan, evaluating possibility of restoring natural grade; and notifying CEQ upon termination of emergency action.
30. Deviation from the normal operation procedures under test 7 of the Experimental Program of Water Deliveries to Everglades National Park.	High levels of rainfall created extreme flooding conditions which threaten endangered species and public safety.	DOD / US Army	January 1998	CEQ approved alternative arrangements that included: immediate distribution of a revised final emergency EA; developing comprehensive plan for public involvement; notifying CEQ if unanticipated impacts occur; formally consulting with FWS after emergency; alternative action to begin immediately and terminate after emergency at which time full NEPA requirements would resume; and providing CEQ with requested information.
31. Remove dead, drowned and severely root- sprung trees that were damaged by windstorm in the National Forests and Grasslands of Texas.	Windstorm caused destruction of habitat for red-cockaded woodpeckers; also gave rise to concerns about risk of high intensity fires and possible bark beetle infestation.	USDA / Forest Service	3/4/1998	CEQ approved alternative arrangements that included: Forest Service preparing an EA; only removing downed, dead or severely root-sprung trees; prioritizing tree removal by an interdisciplinary team; implementing long-term public involvement; not proceeding until emergency consultation under ESA is completed; maintaining records regarding tree removal priorities; establishing on-site monitoring team; and notifying CEQ if any modifications to these arrangements are necessary.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
32. Remove dead, downed and damaged trees in wake of 07/04/99 windstorm affecting 478,000 acres of Superior National Forest. Action proposed for Gunflint Corridor.	One area of affected forest - Gunflint Corridor - is a 2-lane winding, dead-end road with 600 structures, including homes. High risk to people and homes requiring treatment of 3,896 acres.	USDA / Forest Service	8/11/1999 CEQ response: 8/24/1999	CEQ agreed with alternative arrangements that included: preparation of programmatic EA; joint CEQ/FS public meeting; scoping meetings and site visits for particular projects within the Gunflint Corridor; consulting with other interested parties (agencies & tribes); and using on-site monitoring team.
33. Temporary, semipermanent, and permanent flood control measures following Cerro Grande Fire surrounding the Los Alamos National Laboratory in New Mexico.	High risk of soil erosion, flooding and debris flows threaten lives and property of the 10,000 residents in the communities of White Rock, the Pueblo of San Ildefonso and the Pueblo de Conchiti located downstream of Los Alamos National Laboratory.	DOE / National Nuclear Security Administration	May 2000 CEQ response: 6/15/2000	CEQ agreed on alternative arrangements that included: publication of FR notice outlining the emergency actions taken, being undertaken, and intended in the near term to address the effects of the fire as well as the potential impacts of emergency actions and proposed mitigation measures (dam construction); planning for continuing public involvement; preparing and publishing a Special Environmental Analysis; employing monitoring and adaptive mitigation measures; and reporting to CEQ.
34. Reduce wildfire fuel load in approximately 35,000 acres of 147,000 acre “high risk zone” of storm-damaged forest.	340,000 acres of Ouachita National Forest damaged by ice storm, blocked 1700 miles of road, and increasing ten-fold fuel load in forest stands located in close proximity to private property.	USDA / Forest Service	3/15/2001 CEQ response: 3/28/2001	CEQ concurred with alternative arrangements that included: preparing programmatic environmental analysis for highest priority fuel treatments areas; providing for expedited public comment before adopting a final programmatic environmental analysis; completing project-specific EAs before fuel reductions are authorized; and providing those EAs to the public for short comment periods.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
35. Commercial timber harvest on approx. 6200 acres and mechanical treatment of smaller fuels.	6,200 acres of Mark Twain National Forest land within two ¼ to ½ mile swaths of tornado damage (+80% of vegetation leveled) with fire risk to public safety and private property.	USDA / Forest Service	7/8/2002 CEQ Response: 7/12/2002	CEQ concurred with alternative arrangements that included: preparing programmatic environmental analysis for highest priority areas for fuel treatments; providing for expedited public comment before adopting a final programmatic environmental analysis; completing project-specific EA before fuel reductions are authorized that would be made public for short comment periods.
36. Transporting nuclear materials from Libya to the U.S. and within the U.S.	The shipment 55,000 pounds of nuclear material and other sensitive equipment were airlifted out of Libya as directed by the President. To expedite removal of four cylinders of uranium hexafluoride (UF_6) from Libya, the NNSA Administrator invoked the national security provisions of 49 CFR 173.7(b), allowing the shipment.	DOE / National Nuclear Security Administration	Shortly before 1/27/2004	CEQ and the Environmental Protection Agency were briefed in advance of the mission. CEQ found the NNSA's request for alternative arrangements was appropriately limited to the actions necessary to address the immediate impacts and risks associated with this emergency. Based on the briefing that DOE personnel provided, and their commitment to outreach to EPA and appropriate first responders, CEQ concluded that the NNSA's assessment of the environmental impact of the proposed action, including incorporation of an existing classified analysis of a similar scenario, provided sufficient alternative arrangements for NEPA compliance. The CEQ also was briefed following the completion of the mission. See: 69 FR 10440 (March 5, 2004)

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
37. Issue grants under the Stafford Act's Public Assistance Grant Program for the repair, replacement, or restoration of critical infrastructure in the New Orleans Metropolitan Area (NOMA). Although the restoration of eligible infrastructure substantially to its pre-disaster conditions is excluded from NEPA, FEMA anticipated applications from the State would reflect future needs.	Disaster-related damages to critical infrastructure by Hurricane Katrina on 8/29/2005 rendered parts of the city inoperable and uninhabitable. The city could not adequately support reconstruction and repopulation.	DHS / FEMA	Initial contact: November 2005 CEQ Response: 12/6/2005	CEQ approved alternative arrangements to expedite the processing of grant applications. The measures included: regular public outreach including special efforts to involve NOMA residents, including those relocated outside of NOMA; developing an internet page for environmental related public notices and environmental related information specific to the proposed actions in NOMA that would also track other projects in NOMA in order to provide the public with information on the individual and cumulative nature of impacts of the FEMA funded actions; establishing criteria for each type of critical physical infrastructure reconstruction project to mitigate or avoid significant environmental impacts whenever possible; and using the website to document agency actions (receiving, approving, conditioning, or denying critical infrastructure grant applications) as well as their environmental effects. See: https://www.fema.gov/new-orleans-metropolitan-area-infrastructure-projects-6

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
38. The Secretary of Energy issued an emergency order on 12/20/2005 directing Mirant to generate electricity at the coal-fired Potomac River Generating Station in Alexandria, VA, under certain limited circumstances.	Plant's operations were exceeding the National Ambient Air Quality Standards of the Clean Air Act and closure of the plant reduced the reliability of the electrical supply to much of the central business district of the District of Columbia and other portions of Northwest DC, and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Water Treatment Plant, placing these electrical customers in risk of a blackout.	DOE	Consulted 12/20/2005 through 1/17/2006 Request and CEQ response: 1/18/2006	CEQ approved the following alternative arrangements: (1) prepare a Special Environmental Analysis (SEA) that will examine the potential impacts from issuance of the order, and identify potential mitigation measures; (2) provide opportunities for public involvement by disseminating information related to the environmental effects of Mirant's operations and by accepting public comment on this notice, the compliance plan Mirant submitted to DOE, and the SEA; (3) continue consultations with appropriate agencies with regard to relevant environmental issues; and (4) identify in the SEA any steps that DOE believes can be taken to mitigate the impacts from its Order. See: 71 FR 69102 (Nov. 29, 2006)
39. Lower Lake Cumberland behind Wolf Creek Dam to an elevation 680 feet above mean sea level for an indefinite period and accelerate a grouting program in the most crucial areas of the Wolf Creek Dam embankment to further reduce seepage under the dam.	Dam in danger of breaking and flooding down river through Kentucky and into Nashville, Tennessee.	USACE	Contacted: 1/9/2007 Request and CEQ response: 1/18/2007	CEQ approved alternative arrangements requiring USACE to: (1) issue an interim emergency measures decision document including discussion of alternatives and likely environmental effects as they are currently known, coordination with the U.S. Fish and Wildlife Service pursuant to the Endangered Species Act (ESA), the Fish and Wildlife Coordination Act, and other relevant authorities, and with the EPA and other appropriate Federal, state, and local leaders and agencies, and a communication plan for the public and stakeholders; and (2) issue a Notice of Intent to prepare a NEPA document would addresses the Corps' existing and future efforts to preserve, repair, strengthen, and operate the Wolf Creek Dam and Lake Cumberland, including mitigation measures that can be implemented to minimize adverse effects from lowered lake levels and other measures.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
40. New Orleans flood protection.	Reconstruction of levies damaged in Hurricane Katrina for 100-year flood protection.	USACE		See: https://www.mvn.usace.army.mil/Missions/Environmental/NEPA-Compliance-Rebuilding/
41. Navy MFA-sonar training in waters off southern California.	Naval training necessary for deployment.	DOD / US Navy	Request submitted: 1/10-11/2008 CEQ response: 1/15/2008	CEQ granted alternative arrangements calling for the Navy to prepare an environmental assessment an implement a suite of mitigation measures for training proposed during the period necessary to complete an EIS evaluating the environmental impact of establishing mid-frequency active sonar training exercises at the Navy's Southern California Range Complex. See: 73 FR 4189 (Jan. 24, 2008)
42. Temporary suspension of certain NEPA requirements for the Emergency Temporary Interim Rule (ETIR) to support Deepwater Horizon Oil Spill of National Significance Response.	Spill of National Significance (SONS) from the *Macondo* well in the Gulf of Mexico.	DHS / USCG	Request submitted: 7/6/2010 CEQ response: 7/12/2010	CEQ approved alternative arrangements which take the place of an EIS and provide that DHS and the USCG will consider the potential for significant impacts to the human environment as they implemented the ETIR and shift additional response resources from around the country to the Gulf of Mexico to assist in the cleanup of the SONS.
43. Emergency evacuation route along the lava-covered section of Chain Craters Kalapana Road in the Hawai'i Volcanoes National Park.	Established a new evacuation route as existing routes were anticipated to be covered by lava within 45 days.	DOI / NPS	Request submitted: 10/27/2014 CEQ response: 10/30/2014	CEQ approved alternative arrangements requiring the NPS to: (1) continue to enhance public and stakeholder engagement during the implementation of the proposed action; (2) provide responses to public comments received and periodic reports on the results of the monitoring commitments; (3) prepare the NEPA review for the future of the emergency access road after the emergency ends; and (4) continue consulting with affected agencies and stakeholders, adhere to mitigation and monitoring requirements committed to during consultations, and address future consultation or compliance actions as required.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
44. For the Rim Fire Recovery Project in the Stanislaus National Forest, to shorten the draft EIS comment period and eliminate the waiting period before publication of the ROD.	The Rim Fire burned 154,430 acres of National Forest System lands. Immediate action was required to restore the affected lands and mitigate future risks of wildfire.	USDA / Forest Service	Request submitted: 12/5/2013 CEQ response: 12/9/2013	CEQ approved alternative arrangements: continue to enhance public and stakeholder engagement during the scoping initiated by the 12/6/2013 NOI to prepare an EIS; continue engagement of interested parties throughout EIS preparation; continue communication with the Yosemite Stanislaus Solutions collaborative group; continue communication with the Sierra Nevada Conservancy and parties participating in the Rim Fire Landscape Restoration Technical Workshop on 12/18/2013; and post the Final EIS and proposed ROD on the Forest Service website for public review for 5-10 business days prior to publishing the Notice of Availability in the *Federal Register*.
45. Alternative arrangement to shorten the comment period for the draft EIS and eliminate the waiting period before publication of the ROD for fire restoration efforts in the Eldorado National Forest.	The King Fire burned 63,000 acres in California's Eldorado National Forest in 2014. Restoration efforts were needed to prepare for the subsequent wildfire season, especially in light of an ongoing drought.	USDA / Forest Service	Request: 5/7/2015 First CEQ response: 5/14/2015 Second CEQ response: 8/17/2015	CEQ approval based on Forest Service commitments to: (1) enhance collaborative engagement during development of the Draft EIS; (2) provide the interested members of the public with an opportunity to comment on the preferred alternative as it has evolved since the DEIS before finalizing the EIS and ROD and (3) posting the final EIS on the Eldorado National Forest website for public review prior to publishing Notice of Availability in the *Federal Register*.
46. Alternative arrangement to shorten the draft EIS comment period and eliminate the waiting period before publication of the ROD for fire restoration efforts in the Klamath National Forest.	Approximately 183,000 acres of public lands in the Klamath National Forest burned by the Beaver, Happy Camp Complex, and Whites fires in 2014. They were identified as requiring critical treatments to address post-fire conditions.	USDA / Forest Service	Request: 3/6/2015 CEQ Response: 3/6/2015 Remaining Request withdrawn: 8/15/2015	CEQ approved alternative arrangements to shorten the comment period on the Draft EIS based on commitments by the Forest Service to enhance collaborative engagement during development of the Draft EIS. The remaining request was withdrawn in light of ongoing consultation and regulatory processes.

PROPOSED ACTION	NATURE OF EMERGENCY	AGENCY	DATES	RESOLUTION
47. Alternative arrangements for the relocation of the F-22 Formal Training Unit (FTU) to Eglin Air Force Base (AFB).	In October 2018, Hurricane Michael (Category 5) displaced the USAF's only F-22 FTU from Tyndall AFB, Florida, to Joint Base Langley-Eustis in Virginia. Hurricane Michael rendered many of the FTU's facilities unusable for the foreseeable future. The Air Force needed to temporarily relocate the FTU to resume production of trained and qualified F-22 pilots by January 31, 2019.	DOD/Air Force	Request: 12/21/2018 CEQ Response: 12/21/2018 SEA: April 2019 ROD: 4/25/2019	The alternative arrangements required DOD/Air Force immediately to implement five conditions: develop and complete, within 30 days, an EA tiered to a 2014 Eglin AFB EIS documenting the environmental impacts of operations which exceeded the nature and number of flights occurring prior to relocation of the F-22 FTU; provide for distribution, notice of availability, and a 30-day public comment period; provide Air Force responses to substantive comments; and continue efforts to remain alert to opportunities to lessen noise impacts to neighboring communities. The Air Force committed to monitoring and publishing the results, and to preparing an EIS for the permanent beddown of the F-22 FTU.

Exhibit 18

THE SHOOTARING CANYON MILL AND VELVET-WOOD AND SLICK ROCK URANIUM PROJECTS, PRELIMINARY ECONOMIC ASSESSMENT NATIONAL INSTRUMENT 43-101

PREPARED FOR:
Anfield Energy Inc.

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Dated: May 6, 2023

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Section 1: Summary

This Technical Report was prepared for Anfield Energy Inc. (Anfield) by Douglas Beahm, P.E., P.G., of BRS Engineering (author) with contributions by Harold J. Hutson, P.E., P.G. and Carl D. Warren, P.E., P.G., of BRS Inc. and Terrence (Terry) McNulty, P.E., D. Sc., of T.P. McNulty and Associates Inc. to provide a Preliminary Economic Assessment (PEA) of the project based on the reactivation of the Shootaring Canyon mill with feed from the Velvet Wood and Slick Rock mines. The project is planned to recover two mineral products, uranium and vanadium oxides based on the Mineral Resource estimates for the project.

The effective date of this report is May 6, 2023. The effective date of the resource estimation and cost modeling is April 30, 2023.

The author and co-authors are independent "qualified persons" as defined by CIM's National Instrument 43-101 Standards of Disclosure for Mineral Projects (NI 43-101) and as described in Section 28 (Certificates and Signatures).

Mineral Reserves are not estimated herein. This is a restricted disclosure as allowed under section 2.3(3) of NI 43-101 which includes a Preliminary Economic Assessment (PEA) and is preliminary in nature such that it includes a portion of the inferred mineral resources as reported in Section 14 of the report. Mineral resources are not mineral reserves and do not have demonstrated economic viability in accordance with CIM standards. Inferred mineral resources are too speculative to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the outcomes estimated in the PEA will be realized.

1.1 Project Overview

1.1.1 Velvet-Wood Overview

The Velvet and Wood mine projects are located within the Lisbon Valley physiographic province in San Juan County, Utah, as shown in Figure 1.1 and 1.2. The Velvet Mine produced a reported 400,000 tons of ore containing some 4.2 million pounds of uranium (U_3O_8) and 4.8 million pounds of vanadium (V_2O_5) (Chenoweth, 1990).

1.1.2 Slick Rock Overview

The Slick Rock property is located in the southern end of the Uravan mineral belt of the Colorado Plateau physiographic province and at the southeastern edge of the Paradox fold and fault belt in the proximal Disappointment syncline as shown on Figures 1.1 and 1.2. The Slick Rock District is also a past producer with reported production of 2,236,723 pounds of uranium (U_3O_8) and 13,941,457 pounds of vanadium (V_2O_5) (Chenoweth, 1990)

1.1.3 Shootaring Canyon Mill Overview

For the purposes of this PEA, it is assumed that mineral processing will take place at Anfield's mineral processing facility, the Shootaring Canyon Mill, which lies approximately 180 miles from the Velvet-Wood mine area and approximately 200 miles from the Slick Rock mine area, following existing roads as shown on Figure 1.1.

Figure 1.1 - Overall Project Location Map

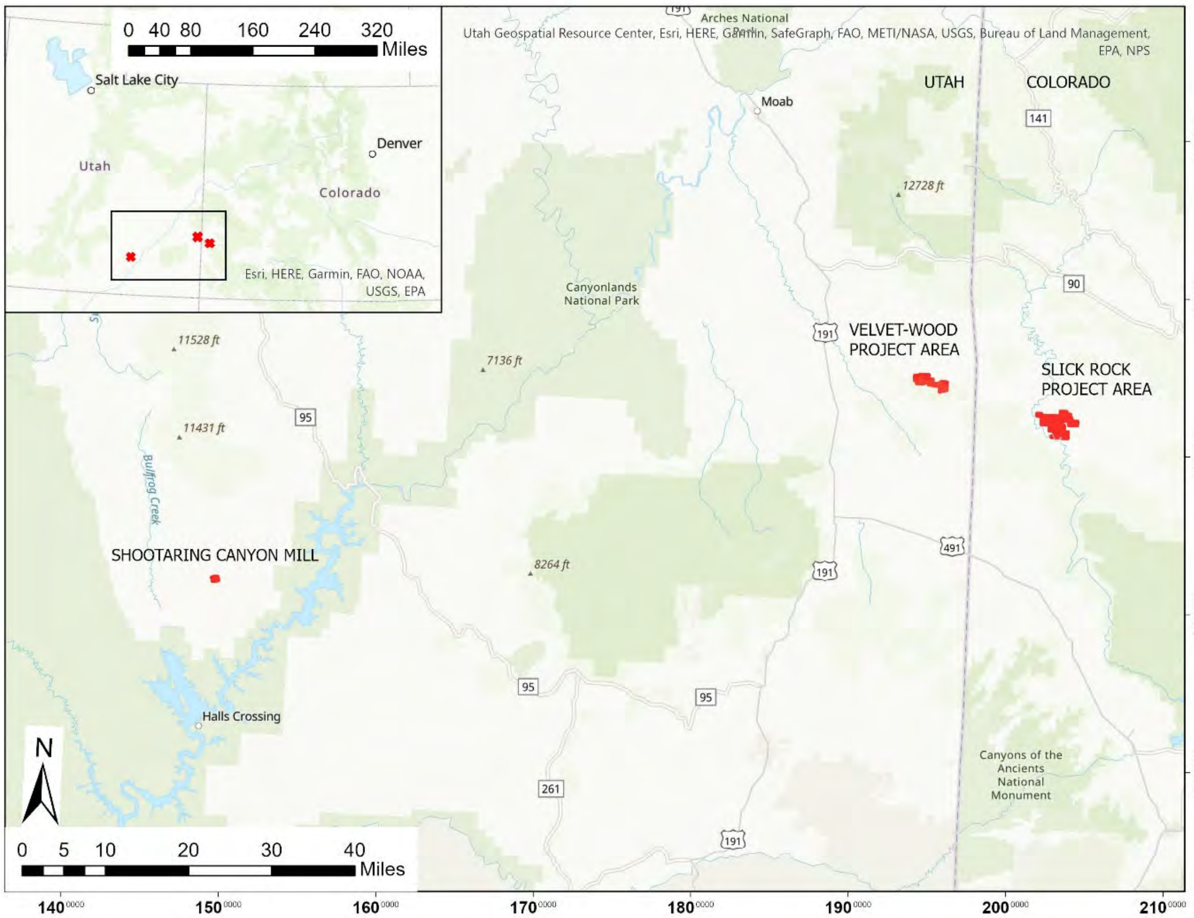
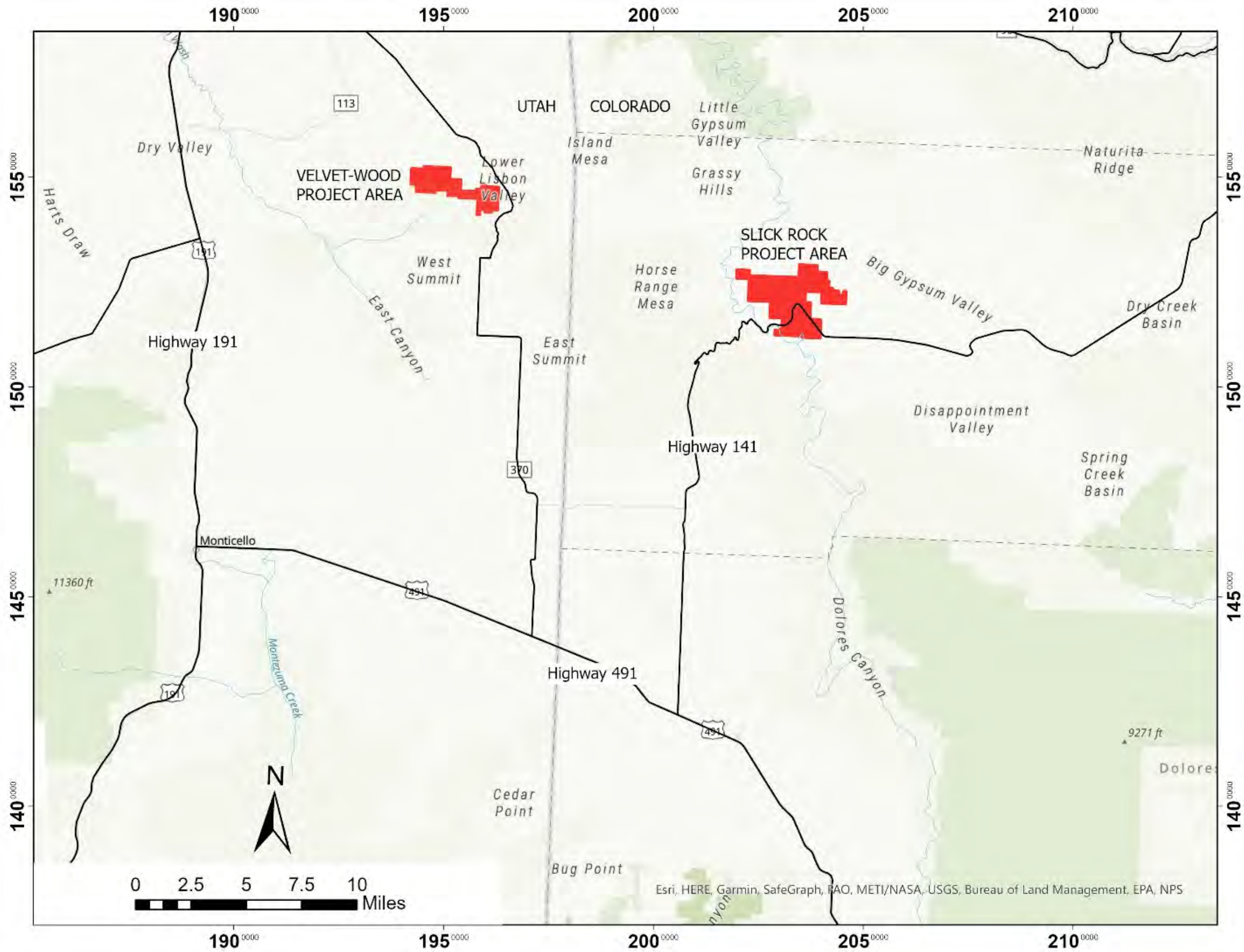


Figure 1.2 - Velvet-Wood and Slick Rock Location and Access Map



1.2 Project Description and Ownership

1.2.1 Velvet-Wood Description and Ownership

The Velvet area is located in San Juan County, Utah, approximately 31 miles from Monticello, Utah, in Township 31 South, Range 25 East, Sections 2, 3, 4 and 10, at Latitude 38° 07’ 00” North and Longitude 109° 09’ 00” West. The Wood area is located in Township 31 South, Range 26 East, Sections 6 and 7 and Township 31 South, Range 25 East, Sections 1, 11, and 12 at Latitude 38° 08’ 00” North and Longitude 109° 06’ 00” West. Project ownership includes unpatented mining claims and a State of Utah mineral lease as shown on Figure 4.1, totaling approximately 2,166 acres related to the Velvet and Wood mine areas as shown on Figure 4.1.

1.2.2 Slick Rock Description and Ownership

The Slick Rock project is located in San Miguel County, Southwest Colorado, approximately 23.9 miles north of the town of Dove Creek, Colorado and east of the Dolores River in the Slick Rock District of the Uravan mineral belt. The approximate geographic center of the property is Latitude 38° 2' 51.7" North, Longitude 108° 51' 42.3" West.

Anfield Energy Inc. entered into a definitive agreement to acquire Slick Rock Property from Uranium Energy Corp. in an asset swap transaction on April 21, 2022. The Slick Rock project is comprised of 268 mineral lode claims included in this report and encompasses an area of approximately 4,976 acres or 7.8 square miles as shown in Figure 4.2. Certain claims within the block are subject to 1% to 3% royalties of net uranium and vanadium production.

1.2.3 Shootaring Canyon Mill Description and Ownership

The Shootaring Canyon Mill is located in Garfield County Utah approximately 52 miles south of Hanksville, Utah in Township 36 South, Range 11 East, Sections 3 and 4 and Township 35 South, Range 11 East, Sections 33 and 34 at approximate Latitude 37º 43’ 00” North and Longitude 110º 41’ 00” West. The Shootaring Canyon Mill is located on lands which are split estate, with the surface estate being fee land held by Anfield, and the mineral estate being Utah State Trust Land held by Anfield through two mineral leases totaling approximately 905 acres of surface and mineral fee lands as shown on Figure 4.3.

1.3 Development Status

1.3.1 Velvet-Wood Development Status

A portion of the Velvet area has been mined by underground mine methods. The mined material from this area was transported to the Atlas mill in Moab, Utah for conventional processing. A mine permit is held for the Velvet Mine. Re-opening of the Velvet Mine would require updating of the mine permit as well as additional permits as subsequently discussed. Access from the former mine operations remain in place. The upper portion of the decline and portal has been closed by backfill and the vent shafts capped at the surface. It is the authors’ opinion that the decline and vents can be re-opened; however, underground conditions are unknown.

The Wood area has not been mined. Site access and drill roads which were not already pre-existing were established under this exploration permit.

1.3.2 Slick Rock Development Status

The Burro No. 3, 5, and 7 Mines were historically operated adjacent to the Slick Rock project and within the northwest corner of the Project Area. These mines were operated as underground random room and pillar mines through the early 1980s. No access agreement currently exists to access the Slick Rock project through the Burro Mines. This PEA is based on the sinking of new mine shafts to access the mineral resources at Slick Rock.

1.3.3 Shootaring Canyon Mill Development Status

The Shootaring Canyon Mill has a Radioactive Materials License (RML) that is administrated by the UDEQ- DWMRC. This license currently authorizes possession of byproduct material (tailings and other milling wastes) and reclamation activities only. A license amendment to return to operational status is needed as are capital improvements, as subsequently discussed in this report.

1.4 History

1.4.1 Velvet-Wood History

The Velvet-Wood mineral holdings have gone through a succession of ownership. Anfield purchased the Velvet-Wood mine along with other conventional uranium assets from Uranium One including the Velvet-Wood project in August 2015.

The Velvet-Wood Uranium Project, as discussed herein, consists of two areas which were historically held by separate companies. The Velvet area was held by Atlas Minerals who mined portions of the mineralization. The Wood area was held during a similar time frame by Uranerz. Uranerz drilled 120 rotary holes from 1985 through 1991 and outlined the current Wood mineral resource area (Chenoweth, 1990). The Wood area as described in this report was drilled but not mined.

1.4.2 Slick Rock History

Surficial to shallow uranium/vanadium mineralization has been known in the Slick Rock area since the early 1900s (then called the McIntyre district). First mined for radium and minor uranium until 1923, numerous companies sporadically operated small scale mining and processing facilities along the Dolores River. In 1931, a mill was constructed by Shattuck Chemical Co. to process vanadium ore. In 1944, the area was worked by the Union Mines Development Corp. for uranium/vanadium ore.

By December of 1955, Union Carbide Nuclear Corp. (UCNC) had drilled out a sufficient resource on the north side of Burro Canyon and began sinking three shafts. In December 1957, the shaft sinking was complete on the Burro No. 3, 5, and 7 mines to total depths of 408 feet, 414 feet, and 474 feet, respectively. In the same year, initial ore shipments were made to UCNC's concentrating mill at Slick Rock.

Anfield Energy Inc. entered into a definitive agreement to acquire Slick Rock Property from Uranium Energy Corp. in an asset swap transaction on April 21, 2022. The Slick Rock project is comprised of 268 mineral lode claims and encompasses an area of approximately 4,976 acres or 7.8 square miles. Certain claims within the block are subject to 1% to 3% royalties of net uranium and vanadium production.

1.4.3 Shootaring Canyon Mill History

The Shootaring Canyon Mill was licensed and constructed by Plateau Resources and has had a succession of owners including US Energy and Uranium One prior to Anfield's acquisition. The mill was constructed by Plateau Resources and operated briefly in 1982. The mill has not been decommissioned and has been under care and maintenance since cessation of operations.

Anfield purchased the Shootaring Canyon mill along with other conventional uranium assets from Uranium One including the Velvet-Wood project in August 2015.

1.5 Regulatory Status

Permitting for Velvet-Wood and Slick Rock mining operations and the reactivation of the Shootaring Canyon mill requires various approvals from the state of Utah, the US Bureau of Land Management, and other agencies including but not limited to the following.

Major actions needed include:

- Reactivation of the mill
  - The existing Source Material License, UT0900480, issued by UDEQ/DRC, requires an amendment to convert from the current care and maintenance status to operational status.
  - Current updates include an investigation by PSE which will provide both substantial designs for the rehabilitation of the mill and a basis for amending the mill license; and a reclamation design for the mill tailings by Engineering Analytics. These studies are scheduled to be completed by June and fall 2023, respectively.
  - The mill is being maintained along with all additional permits and licenses and required environmental monitoring programs.
- Velvet-Wood Mine
  - The existing Large Mine Permit, UTU68060, issued by DOGM and the Plan of Operations issued by BLM require an amendment to convert from current care and maintenance status of operational status and to include the Wood portion of the mine.
  - The existing ground water discharge permit, UGW170003, issued by UDEQ/WQD will require amendment. If uranium is recovered from the ground water this would require licensing action by UDEQ/DRC.
- Slick Rock Mine
  - A new Large Mine Permit and Plan of Operations is required to be issued by CMLRB and BLM, respectively.
  - If it were necessary to recover uranium onsite from ground water treatment in order to meet discharge permit requirements, a source materials license from CDPHE would be required.
- Permits common to all operations.
  - Air quality permits.
  - Water quality permits, storm water discharge (construction and operations).
  - Monitor well permits.
  - Water rights for consumptive use.
  - Federal Mine Safety for mine and mill under the Mine Safety and Health Administration (MSHA).

1.6 Geology and Mineralization

1.6.1 Velvet-Wood Geology

The Velvet-Wood project is located in the Lisbon Valley uranium district which was the largest uranium producing district in Utah. The Lisbon Valley or Big Indian Wash District produced 5 times as much uranium as any other district in Utah from the period of 1948 through 1988 totaling some 77,913,378 pounds U_30_8 at an average grade of 0.30 % U_30_8 (Chenoweth, 1990). Uranium mineralization in the Velvet and Wood areas is found in sandstone units within the Cutler Formation. The sandstones are fluvial arkose that has been bleached. The mineral deposits are irregular tabular bodies (Denis, 1982) located at the base, at the top, or close to pinch-outs of the sandstone bodies (Campbell and Mallory, 1979). The major producing zone in the Cutler occurs near the unconformity between the Cutler and the overlying Chinle Formation.

1.6.2 Slick Rock Geology

Uranium/vanadium mineralization is hosted by the Upper Jurassic Morrison Formation and is typical of Colorado Plateau-style uranium/vanadium deposits. Past production came from the upper or third-rim sandstone of the Salt Wash member of the Morrison Formation. This is the target host for uranium/vanadium mineralization within Anfield's Slick Rock project area.

Uranium and vanadium-bearing minerals occur as fine-grained coatings in detrital grains filling pore spaces between the sand grains and replacing carbonaceous material and some detrital grains (Weeks et al., 1956). The primary uranium minerals are uraninite (UO_2) with minor amounts of coffinite ($USiO_4OH$). Montroseite (VOOH) is the primary vanadium mineral, along with vanadium clays and hydromica. Metal sulfides occur in trace amounts. Mineralization occurs within tabular to lenticular bodies that are peneconcordant within sedimentary bedding. Mineralization may also cut across sedimentary bedding to form irregular shapes.

1.7 Exploration and Drilling Status

1.7.1 Velvet-Wood Exploration and Drilling

Drill data is available for a total of 325 drill holes. Of this total 268 drill holes are of a historic nature and 57 were completed by Uranium One in the 2007/2008 time period. Relevant data including geophysical and lithological logs are available for both recent and historic drilling. 46% of the drill holes encountered uranium mineralization in excess of the recommended cutoff criteria, an additional 41% showed low grade to trace mineralization, and the remaining drill holes were barren and/or not completed to the host horizon.

1.7.2 Slick Rock Exploration and Drilling

A total of 312 drill holes are available for the Slick Rock Project Area. All of the drill holes are considered historic. Of this total, 27 holes have location data but no additional data associated with them. These 27 holes were excluded from the resource modeling. The remaining 285 holes contain 346 unique intercepts.

1.8 Mineral Resource Summary

This report summarizes mineral resource for the Velvet-Wood and Slick Rock mines with mineral processing at common facility, the Shootaring Canyon mill. A detailed description of the mineral resource estimation methodology and results is provided in Section 14. Mineral resources have been estimated for both uranium and vanadium as the mineralization occurs primarily as uranyl-vanadates, and the refurbishment of the Shootaring Canyon mill will include a vanadium circuit to recover the vanadium as a co-product with the uranium.

The total estimated uranium mineral resources are summarized in Table 1.1. The associated vanadium mineral resource which will be mined as a co-product is summarized in Table 14.2.

Table 1.1 - Velvet-Wood & Slick Rock Uranium Mineral Resource Summary*

Area/Classification	GT Cutoff	Pounds eU_3O_8	Tons	Average Grade $\%eU_3O_8$
TOTAL MEASURED AND INDICATED MINERAL RESOURCE URANIUM	0.25 – 0.50	4,627,000	811,000	0.29
TOTAL INFERRED MINERAL RESOURCE URANIUM	0.25 – 0.40	8,410,000	1,836,000	0.24

*Numbers rounded

Table 1.2 - Velvet-Wood & Slick Rock Vanadium Mineral Resource Summary*

Area/Classification	GT cutoff (Based on Uranium)	V:U Ratio	Pounds V_2O_5	Tons	Avg Grade $\%V_2O_5$
TOTAL INFERRED MINERAL RESOURCE VANADIUM	0.25-0.50	4.2	54,399,000	2,647,000	1.03

*Numbers rounded

While mineral resources are not mineral reserves and do not have demonstrated economic viability, reasonable prospects for future economic extraction were applied to the mineral resource estimates herein through consideration of grade and GT cutoffs as well as mineralization proximity to existing and proposed conceptual mining. As such, economic considerations were exercised by screening out areas which were below these cutoffs or of isolated mineralization and thus would not support the cost of conventional mining under current and reasonably foreseeable conditions.

1.9 Preliminary Economic Assessment

Project cost estimates are based on a conventional random room and pillar underground mine operation at the Velvet-Wood and Slick Rock mine areas. Mined material would be hauled by truck to the Shootaring Canyon Mill approximately 180 miles from Velvet-Wood and 200 miles from Slick Rock. The mill would be fully refurbished and would process mined material for both uranium and vanadium recovery.

All costs are estimated in constant 2022 US Dollars. Operating (OPEX) and Capital (CAPEX) costs reflect a full and complete operating cost going forward including all pre-production costs, permitting costs, mine costs, and complete reclamation and closure costs for of the mine and mineral processing facility. CAPEX does not include sunk costs or acquisition costs.

Commodity prices used in this PEA are discussed in Section 19 and are $70 per pound for uranium oxide and $12 per pound for vanadium pentoxide.

A current investigation and design study for the reactivation of the Shootaring Canyon Mill has been commissioned by Anfield who has engaged the firm of Precision Systems Engineering (PSE) of Salt Lake City, Utah for this study. The PSE study will provide substantial designs for the rehabilitation of the mill, will provide a basis updating the mill license, and will consider options for increasing the mill throughput. The initial study is scheduled to be completed by June 2023, while a report outlining advanced engineering and design is expected to be completed in fall 2023.

Mine design and permitting for the Velvet Wood and Slick Rock mines are also ongoing. It is recommended that this PEA be revised following completion of this investigation and study.

Mining and mineral recovery methods are described in Sections 16 and 17, respectively. Capital and operating costs, CAPEX and OPEX, are discussed in Section 21.

- Total initial CAPEX, not including current and sunk costs, is estimated at $122.3 million USD (refer to table 21.1).
- Total weighted average OPEX is estimated at $244 USD per ton mined and processed (refer to Table 21.3).
- The total cost per ton to produce saleable uranium and vanadium products is estimated at $290 USD per ton. This compares to an estimated gross value of $741 USD per ton (refer to Table 21.3).

For the purposes of this PEA, it was assumed that the Shootaring Canyon Mill would be refurbished to its original 750 tons per day capacity and a vanadium recovery circuit would be added. The PEA considers simultaneous mine feed from the Velvet-Wood decline and two production shafts at Slick Rock. Given the selective nature of the mining and the geometry of the mineralization, three production centers are needed to meet the mill tonnage capacity. Referring to the cash flow model Table 22.4 at the end of this section, the currently defined mineral resource at Velvet-Wood would be mined out in 8 years while production from the two shafts at Slick Rock would continue for 15 years. Thus, additional mill tonnage capacity would be available beginning in year 9. Additional mill feed could be sourced as captive feed from other Anfield mineral resource holdings in the Colorado Plateau or from mineral resource holdings of others under toll milling agreements.

The base case is based on commodity prices of $70 per pound for uranium oxide and $12 per pound for vanadium pentoxide with respective mill recoveries of 92% and 75%, respectively. The base case economic evaluation shows:

- Pre-tax IRR 40%
- Post-tax IRR 33%
- Pre-Tax NPV (8% discount rate) $238,398 $US x 1,000
- Post-Tax NPV (8% discount rate) $196,768 $US x 1,000

Breakeven with respect to commodity price occurs when the base case commodity prices are reduced by 40% to $42/lb and $7.20/lb, respectively.

This project, like all similar projects, is quite sensitive to commodity prices as shown in Figures 1.31 and 1.4 for pre and post income tax NPV, respectively.

Figure 1.3 – NPV Price Pre-Tax Sensitivity Chart

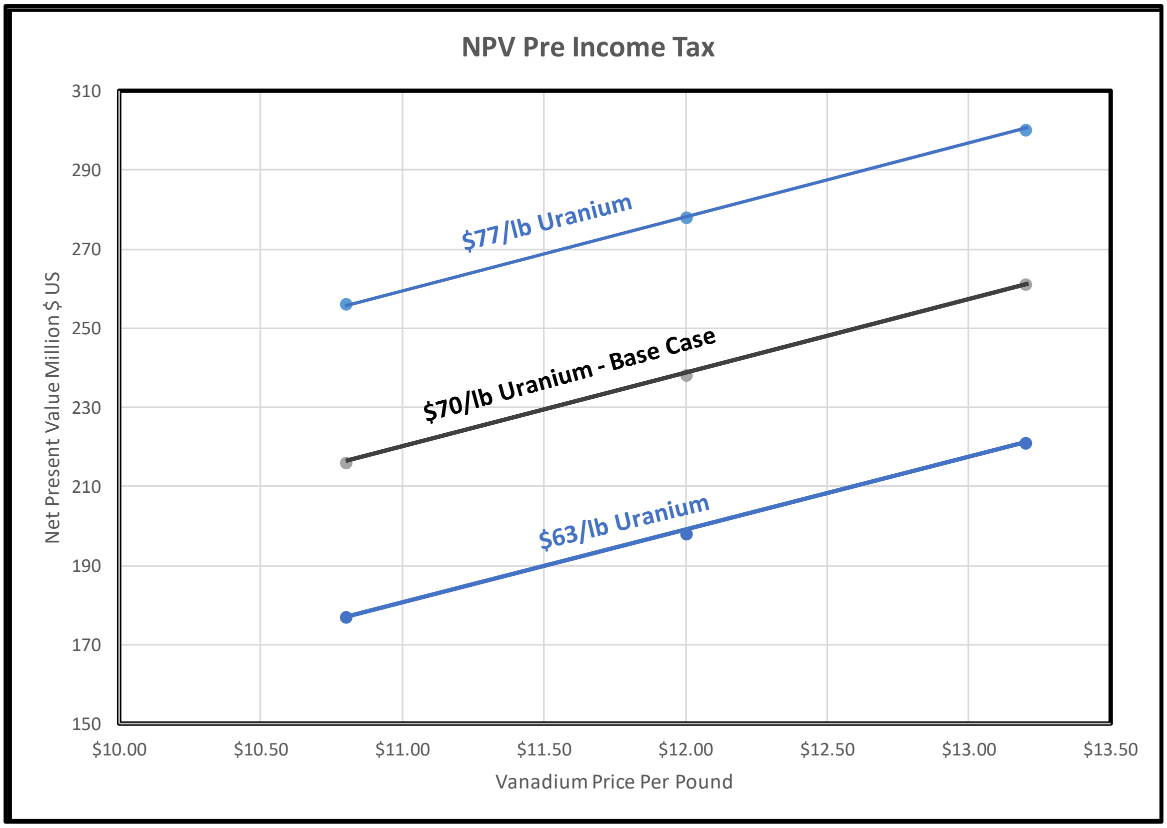
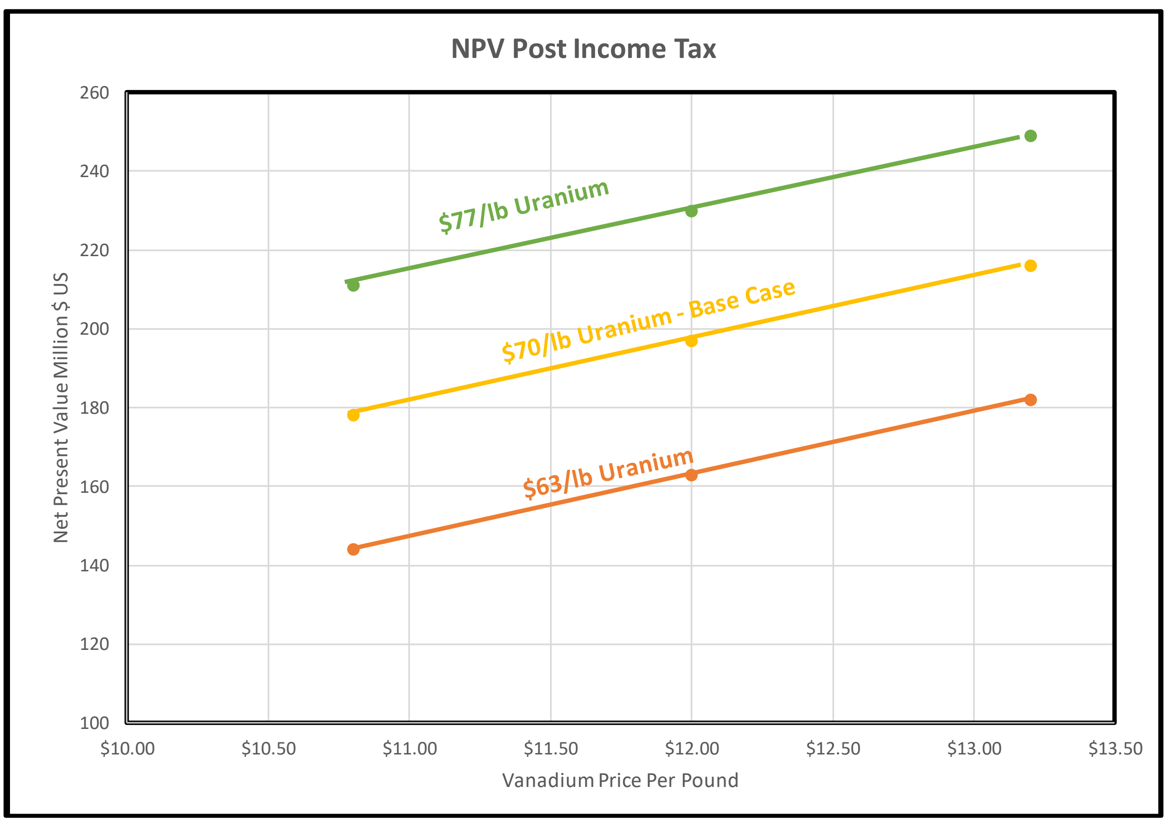


Figure 1.4 – NPV Price Post-Tax Sensitivity Chart



This is a restricted disclosure as allowed under section 2.3(3) of NI 43-101 which includes a Preliminary Economic Assessment (PEA) and is preliminary in nature such that it includes a portion of the inferred mineral resources as reported in Section 14 of the report. Mineral resources are not mineral reserves and do not have demonstrated economic viability in accordance with CIM standards. Inferred mineral resources are too speculative to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the outcomes estimated in the PEA will be realized.

1.10 Summary of Risks

The authors are not aware of environmental, permitting, legal, title, taxation, socio-economic, marketing, political, or other relevant factors not stated herein which would materially affect the mineral resource estimates or the results of the PEA. To the authors' knowledge there are no other significant factors that may affect access, title, or the right or ability to perform work on the property, provided the conditions of all mineral leases and options and relevant operating permits and licenses are met. A summary of risks follows, categorized in terms of economic, technical, and permitting and licensing risks.

Economic Risks:

This report includes disclosure permitted under Section 2.3(3) of NI 43-101 as the Preliminary Economic Assessment (PEA) includes a portion of the inferred mineral resources reported in Section 14 of the report. Mineral resources are not mineral reserves and do not have demonstrated economic viability. A Preliminary Feasibility Study (PFS) is required, at a minimum, to demonstrate the economic viability of the measured and indicated mineral resources and qualify an initial estimate of mineral reserves.

The PEA is preliminary in nature and includes inferred mineral resources that are considered too speculative geologically to have economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the preliminary economic assessment will be realized.

Technical Risks:

It is the authors' opinion that the technical risks associated are low for the following reasons:

- Portions of deposit have been successfully mined in the past.
- Uranium has been successfully extracted from mined material via conventional milling.
- The Project has some of the required operating permits and facilities in place.

The Project does have some risks similar in nature to other mining projects in general and uranium mining projects specially, i.e., risks common to mining projects including:

- Future commodity demand and pricing.
- Environmental and political acceptance of the project.
- Variance in capital and operating costs.
- Mine and mineral processing recovery and dilution.

- Continuity of mineralization with respect to thickness and grade may vary.
- Mining claims are subject to the Mining Law of 1872. Changes in the mining law could affect the mineral tenure.
- There is a risk that underground conditions at the Velvet Mine and/or the Slick Rock Mine may limit access to mineral resources.

The authors are not aware of environmental, permitting, legal, title, taxation, socio-economic, marketing, political, or other relevant factors which would materially affect the mineral resource estimates, provided the conditions of all mineral leases and options, and relevant operating permits and licenses are met.

Permitting and Licensing Risks:

- The BLM could require updated baseline environmental studies and initiate the National Environmental Policy Act (NEPA) process if the updated mine plan deviates significantly from the scope of the currently approved but outdated plan. This could have substantial cost and schedule impacts, as discussed in Section 20.
- The Colorado Department of Health and/or Utah Department of Environmental Quality - Division of Waste Management and Radiation Control could require a Source Materials License if mine dewatering treatment wastes exceed the minimum quantities identified in 10 CFR §40.22 (more than 150 lbs of material with greater than 0.05% natural uranium), which would incur risks of additional costs and extended schedule.

1.11 Recommendations

The following recommendations relate to potential improvement and/or advancement of the Project and fall within two categories; recommendations to potentially enhance the resource base and recommendations to advance the Project towards development. Both may be conducted contemporaneously.

The Slick Rock project will require a Phase 1 verification drilling program to confirm the existing database and upgrade the resource category. This would be followed by Phase 2 of work, including delineation drilling, updating resource model, and preparation of a PEA update or PFS. The Velvet mine does not require an initial phase of verification and would be included along with Slick Rock in Phase 2.

Phase 1 costs total $550,000 USD and are summarized on Table 26.1.

The Phase 2 recommendations and cost estimates for the Velvet-Wood Project are provided in Table 26.2. The Phase 2 recommendations and cost estimates for the Slick Rock Project are provided for future reference in Table 26.3.

Total Phase 2 cost is estimated at $4.5 million USD.

1.12 Terms and Abbreviations

Table 1.5 provides a brief list of terms and abbreviations used in this report:

Table 1.5 - Terms and Abbreviations

GENERAL TERMS AND ABBREVATIONS					
	METRIC		US		Metric: US
	Term	Abbreviation	Term	Abbreviation	Conversion
Area	Square Meters	M^2	Square Feet	Ft^2	10.76
	hectare	Ha	Acre	Ac	2.47
Volume	Cubic Meters	m^3	Cubic Yards	Cy	1.308
Length	Meter	m	Feet	Ft	3.28
	Meter	m	Yard	Yd	1.09
Distance	Kilometer	km	Mile	mile	0.6214
Weight	Kilogram	Kg	Pound	Lb	2.20
	Metric Ton	km^3	Short Ton	Ton	1.10
Currency			US Dollars	$US	
URANIUM / VANADIUM SPECIFC TERMS AND ABREVATIONS					
Uranium Oxide Grade	Parts Per Million	ppm U_3O_8	Weight Percent	%U_3O_8	
Vanadium Oxide Grade	Parts Per Million	Ppm V_2O_5	Weight Percent	%V_2O_5	
Radiometric Equivalent Grade		ppm eU_3O_8		% eU_3O_8	
Thickness	meters	m	Feet	Ft	
Grade Thickness Product	grade x meters	GT(m)	grade x feet	GT(Ft)	

Section 2: Introduction

2.1 Purpose of Report and Authors

This Technical Report was prepared for Anfield Energy Inc. (Anfield) by Douglas Beahm, P.E., P.G., of BRS Engineering (author) with contributions by Harold J. Hutson, P.E., P.G. and Carl D. Warren, P.E., P.G., of BRS Inc. and Terrence (Terry) McNulty, P.E., D. Sc., of T.P. McNulty and Associates Inc. to provide a Preliminary Economic Assessment (PEA) of the project based on the Mineral Resource estimates for the project.

The portions of the report completed by BRS were written under the direction of Douglas Beahm, P.E., P.G. The author and co-authors are independent "qualified persons" as defined by CIM's National Instrument 43-101 Standards of Disclosure for Mineral Projects (NI 43-101) and as described in Section 28 (Certificates and Signatures).

2.2 Extent of Authors' Field Involvement

2.2.1 Velvet-Wood Site Visits

Mr. Beahm attempted to visit the Velvet-Wood site on February 14, 2023, however, the site was inaccessible due to winter conditions. Previously Mr. Beahm visited the project and Uranium One's Moab office, which at the time was the repository of the project data, on September 16, 2014. During this time Mr. Beahm inspected drill sites from the latest period of drilling completed by Uranium One (2007 and 2008) and obtained copies of this and previous data including copies of geophysical logs, location maps, and database summaries. Mr. Beahm was also present on site on numerous occasions during 2007 and 2008 and participated in the verification drilling and coring programs.

Mr. Warren and Mr. Hutson inspected the Velvet-Wood mine area on April 13, 2023. The access road to the closed portal and reclaimed waste pile area was utilized to access the portal location. The waste dump was observed to be reclaimed with vegetative cover on the top. No elevated gamma readings were observed at any location on the Velvet or Wood properties due to the depth to the mineralized zone.

The powerlines to the site have been recently removed and the right of ways remain cleared. The upper closed fan shaft with water sampling access and the upper well were accessible from drill access leaving the county road. All of the wells were locked.

The water treatment site was inspected. The site has been reclaimed and revegetated. Diversion ditches around the site remain but require maintenance.

Multiple historic drill access routes exist on site where the pinon and juniper trees have been removed. Historic drill pad locations were observed at the Velvet area but no open holes were located. Historic drill pad locations and an open drill hole were observed on Three Step Hill above the Wood deposit area.

2.2.2 Slick Rock Site Visits

Mr. Beahm conducted a recent site visit on February 14, 2023. Mr. Beahm previously completed a site visit on April 2, 2013. At the time he was able to access the Burro mine workings which were above the ground water table. In addition to observing the decline, approximately 1,500 feet of mine workings were examined. In addition, Mr. Beahm inspected evidence of previous drilling, the existing vent shaft on the Slick Rock property, and examined potential sites for mine entry. Based on his recent site visit, the only significant change was related to reclamation of the DOE legacy site and mine waste pile associated with the Burro mine. None of these changes materially affect the Slick Rock property.

Mr. Warren and Mr. Hutson visited the Slick Rock Site on April 12, 2023 and met with the Burro Mine's owner, Don Coram, who provided access to the Burro Mine. The Burro Mine is adjacent to the Slick Rock project in the same mineralized horizon, and was historically used for access to the Slick Rock mineralized zone as discussed in Section 6. Mr. Warren and Mr. Hutson entered the Burro mine through a grated entry gate. The adit was 8 feet in height by 9 to 10 feet wide, and the ground conditions were good. The mineralized zone was measured at the first crosscut within 200 feet of the portal, in the rib near the floor at approximately 3,000 microRem per hour. The mineralized material was tested with a portable XRF unit, which measured 1.02% U and 4.52% V. The use of the Burro Mine to access Anfield's resources was discussed and was of interest to Mr. Coram.

Mr. Warren and Mr. Hutson then inspected the top of the mesa above the Slick Rock mineralized area. Claim posts and historic drill pads were observed. Core was found lying on the surface at most of the historic drill pads but was in disarray. No mineralized core was observed. Shallow mud pits were partially filled by erosion at each historic drill pad location. An overhead powerline and a gas line passed through the site as shown on Figure 16.3.

2.2.3 Shootaring Canyon Mill Site Visits

Mr. Beahm recently visited the Shootaring Canyon mill on February 16, 2023. During this time Mr. Beahm observed that the mill stockpiles remained in place, the tailings impoundment was intact, the general condition of the mill was similar to its condition in during Mr. Beahm's previous visits in 2007 and 2008, and the mill, office and general facility was well kept and maintained.

Dr. McNulty did not conduct a recent site visit to the mill but was present at the site on numerous occasions during the period of 2007 and 2008 when the evaluation of the mill was being conducted by Lyntek and the report entitled "Definitive Cost Estimate for the Restart of Shootaring Canyon Mill Ticaboo, Utah" was completed on March 28, 2008, by Lyntek, Inc. (Lyntek, 2008). Dr. McNulty contributed to this report and provided peer review of the report.

2.3 Sources of Information and Data

In preparing the Technical Report, the authors relied on geological reports, maps, and miscellaneous technical papers listed in Section 27, References. The information, conclusions, opinions, and estimates contained herein are based on:

- The qualified person’s field observations.
- Data, reports, and other information publicly available or provided by Anfield.
- Previous experience with similar deposits.
- Drill hole data as discussed in Section 12.

2.4 Report Terms of Reference

All measurement units used in the report are imperial units, and currency is expressed in U.S. dollars (US$) unless stated otherwise.

Reported mineral resources are in situ.

Section 3: Reliance on Other Experts

The location, extent, and terms relating to mineral tenure were provided by Anfield and were relied upon as defining the mineral holdings of Anfield in the development of this report.

For the purpose of Sections 4, Property Description and Location, Mineral Tenure, and Ownership of this report, the authors have relied on ownership data (mineral, surface, and access rights) provided by Anfield. The accuracy of the information was not verified by the authors. The authors have not researched the property title or mineral rights for the project and express no legal opinion as to the ownership status of the property. However, Anfield provided copies of the mineral claim lease and purchase agreement which were reviewed for content by the authors. All mining claims whether leased, purchased, or located by Anfield were verified as to their validity by searching the BLM online LR2000 web site. BLM lists the mining claims as current.

The terms of the Asset Purchase Agreement with Uranium One were provided by Anfield and were relied upon in the development of this report.

The authors have fully relied upon the Frasier Institute Annual Survey of Mining Companies 2021 for the assessment of public policies that affect mining investment.

Section 20 of the report in its entirety and the portions of Section 1, 4, 25, and 26 related to permitting requirements, bonding, and related conclusions and recommendations were provided by Mr. Toby Wright, Wright Environmental under a third-party contract with Anfield. The authors have worked with Mr. Wright on several other uranium projects and consider the information provided for this report to be reliable.

The authors have reviewed the information provided by Anfield with respect to mineral tenure, the Asset Purchase Agreement, and status of environmental permits to the extent available through the public record and finds the information provided by Anfield to be in keeping with industry standards as appropriate for inclusion in the PEA.

Section 4: Property Description

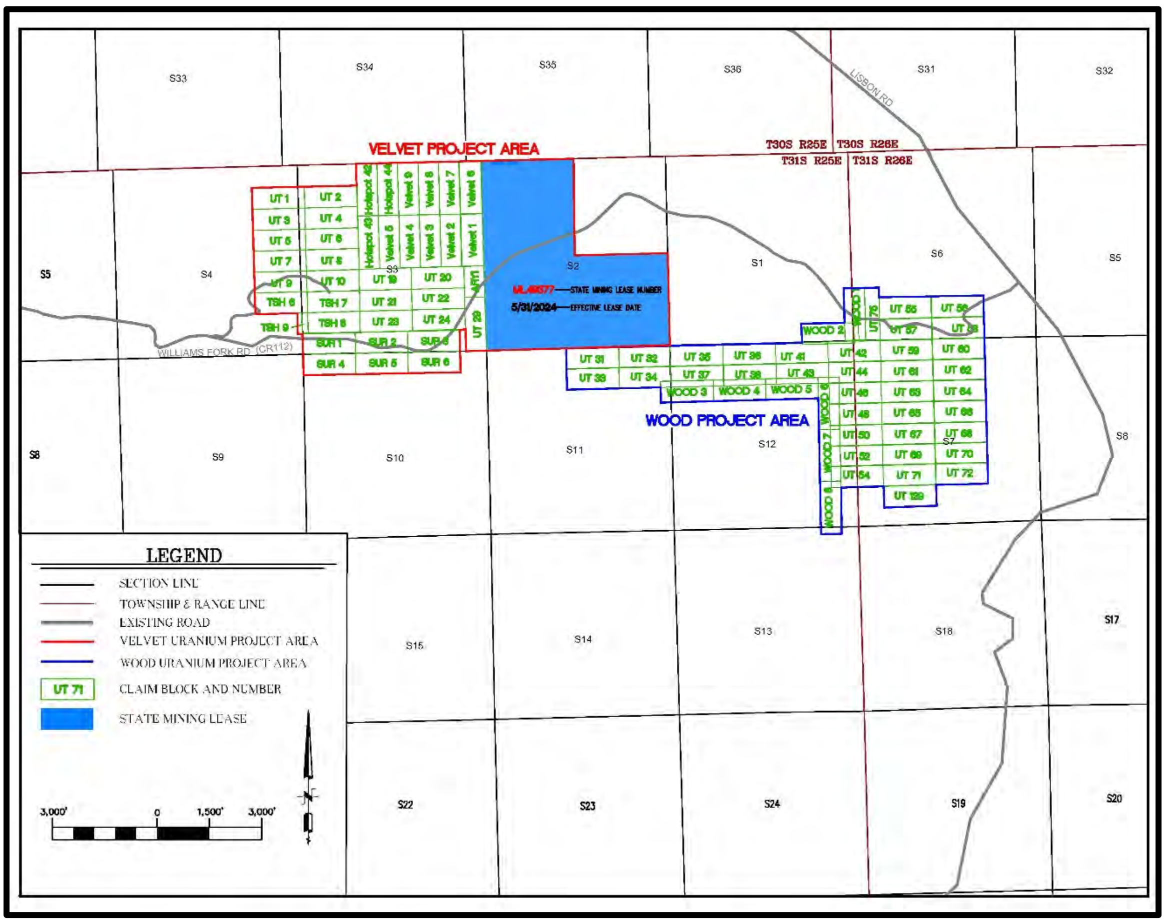
4.1 Property Description and Location

4.1.1 Velvet-Wood Property Description

The Velvet area is located in San Juan County, Utah, approximately 31 miles from Monticello, Utah in Township 31 South, Range 25 East, Sections 2, 3, 4 and 10, at Latitude 38° 07' 00" North and Longitude 109° 09' 00" West. The Wood area is located in Township 31 South, Range 26 East, Sections 6 and 7 and Township 31 South, Range 25 East, Sections 1, 11, and 12 at Latitude 38° 08' 00" North and Longitude 109° 06' 00" West.

In total the mineral holdings within the Project area comprise approximately 2,140 acres. (See Figure 4.1, Overall Project Location Map).

Figure 4.1 - Velvet-Wood Ownership and Claim Map



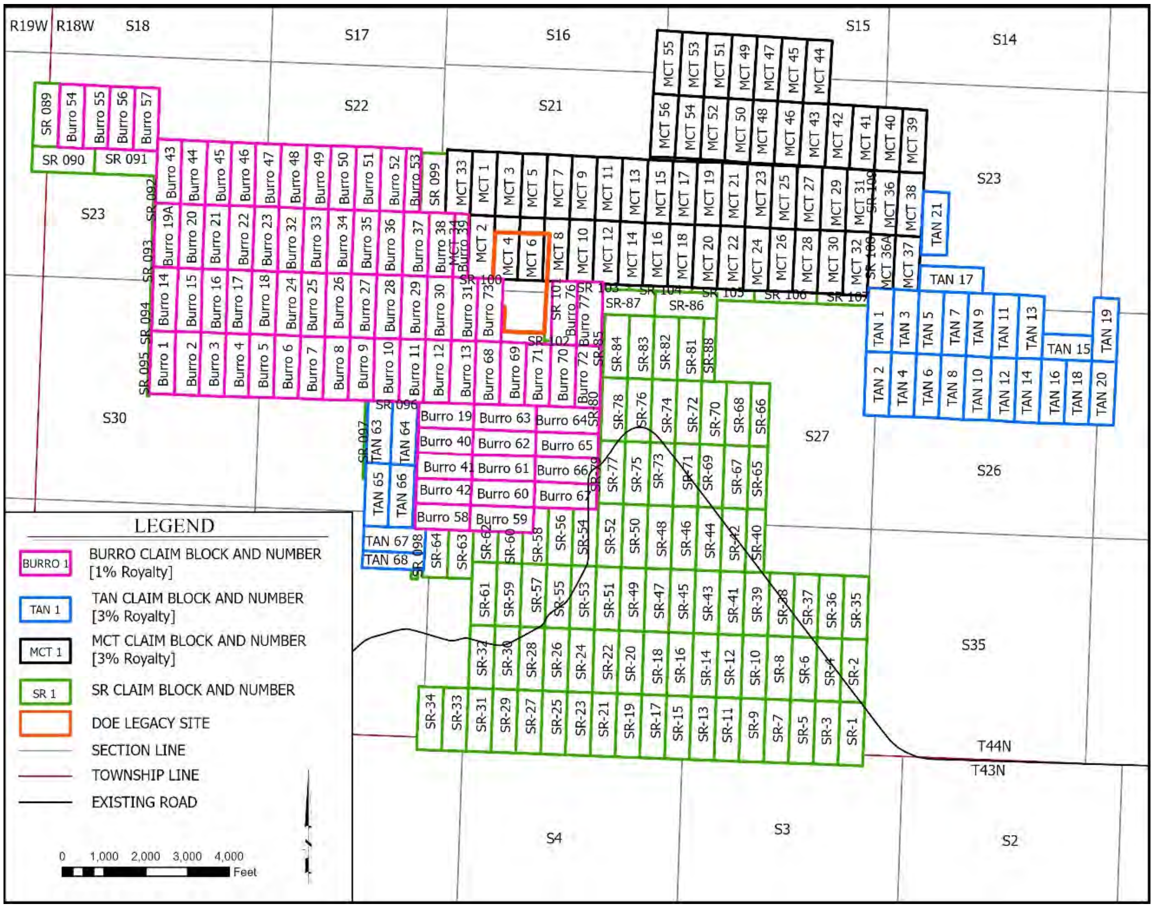
4.1.2 Slick Rock Property Description

The Slick Rock project is located in San Miguel County, Southwest Colorado, approximately 24 miles north of the town of Dove Creek and east of the Dolores River in the Slick Rock District of the Uravan mineral belt. The Slick Rock project is located in Township 44 North, Range 18 West, Sections 15, 16, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 32, 33, and 34 and in Township 43 North, Range 18 West, Sections 3, 4, and 5. The approximate geographic center of the property is

Latitude 38° 2' 51.7" North, Longitude 108° 51' 42.3" West. In total the mineral holdings within the Project area comprise approximately 4,976 acres as shown on Figure 4.2.

The Slick Rock project is bordered to the west by Department of Energy (DOE) uranium lease tracts C-SR-13 and C-SR-13A; to the southwest by DOE uranium lease tract C-SR-14; and to the north and northeast by Energy Fuels' recently acquired Sunday-Carnation-Topaz-St. Jude mine complex, formerly operated by Denison Mines Corp.

Figure 4.2 - Slick Rock Ownership and Claim Map

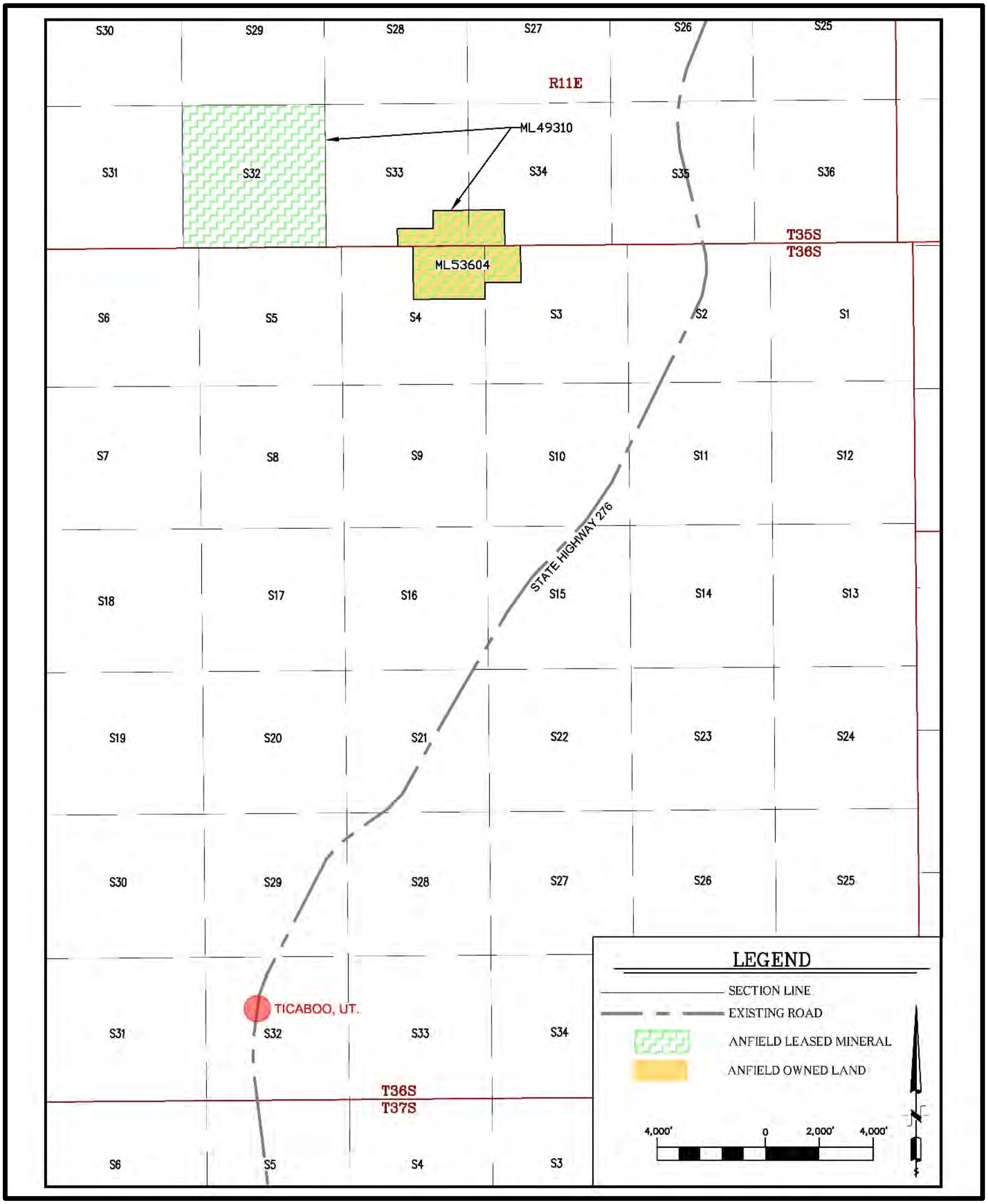


4.1.3 Shootaring Canyon Mill Property Description

The Shootaring Canyon Mill is located in Garfield County Utah approximately 52 miles south of Hanksville, Utah in Township 36 South, Range 11 East, Sections 3 and 4 and Township 35 South, Range 11 East, Sections 33 and 34 at approximate Latitude 37° 43' 00" North and Longitude 110° 41' 00" West.

The Shootaring Canyon Mill is located on lands which are split estate as shown on Figure 4.3, Shootaring Canyon Mill Ownership Map. The surface estate is fee land held by Anfield, and the mineral estate is Utah State Trust Land held by Anfield through two mineral leases.

Figure 4.3 - Shootaring Canyon Mill Ownership Map



4.2 Ownership and Mineral Tenure

4.2.1 Velvet-Wood Mineral Tenure

Figure 4.1, Velvet-Wood Mineral Ownership and Claim Map, shows the approximate location of unpatented mining lode claims and state leases that are part of the Velvet-Wood Project. Copies of recent claim filings with the BLM for unpatented mining lode claims were provided by Anfield. The entire Velvet Wood project encompasses an area of approximately 2,140 acres.

Unpatented mining claims, both lode and placer, are under the authority of the Mining Law of 1872 on federal lands administered by the Bureau of Land Management (BLM). Under the Mining Law, the locator has the right to explore, develop, and mine on unpatented mining claims without paying production royalties to the federal government. Claim maintenance fees of $165 per claim are due by September 1st of each year. Unpatented federal lode mining claims are designated in the field by four corner posts, two end-center posts, and a location monument. Claim location notices for each unpatented claim are recorded in the county recorder’s office of the county in which the claims are located, and then filed with the BLM State office.

In addition to the mining lode claims, three quarters of Section 2 is a State of Utah lease ML 49377. To maintain these mineral rights Anfield must comply with the state lease provisions including annual payments to State of Utah for leases ML 49377 and BLM and San Juan County, Utah filing and/or annual payment requirements to maintain the validity of the unpatented mining lode claims.

4.2.2 Slick Rock Mineral Tenure

Figure 4.2, Slick Rock Ownership and Claim Map, shows the approximate location of the unpatented mining claims on the project. The project contains four claim blocks. The Burro claim block consists of 76 claims. The SR claim block consists of 131 claims, of which 109 were included in the study area for this report, with the remainder located outside of the project area. The TAN claim block consists of 27 claims. The MCT claim block consists of 56 claims. The MCT and TAN claims are leased from UR Energy. A total of 268 mineral lode claims were utilized for the Slick Rock mineral resource estimate in this report, encompassing an area of approximately 4,976 acres or 7.8 square miles.

To maintain these mineral rights Anfield must comply with the BLM and San Miguel County, Colorado filing and/or annual payment requirements to maintain the validity of the unpatented mining lode claims.

4.2.3 Shootaring Canyon Mill Mineral Tenure

The Shootaring Canyon Mill is located on lands which are split estate as shown on Figure 4.3, Shootaring Canyon Mill Ownership Map. The surface estate is fee land held by Anfield, and the mineral estate is Utah State Trust Land held by Anfield through two mineral leases as follows.

Surface Ownership:

- Township 35 South, Range 11 East, SLB&M, Section 33: S/2SW/4SE/4, SE/4SE/4, Section 34: SW/4SW/4, W/2SE/4SW/4
- Township 36 South, Range 11 East, SLB&M, Section 3: Lot 4, Section 4: Lots 1, 2, N/2S/2NE/4

- Approximately 264.52 Acres

Mineral Ownership:

- State of Utah Lease ML 53604, Township 36 South, Range 11 East, Section 3: Lot 4, Section 4: Lots 1, 2, N/2S/2NE/4
- Approximately 144.5 Acres
- State of Utah Lease ML 49310, Township 35 South, Range 11 East, Section 32: All, Section 33: S/2SW/4SE/4, SE/4SE/4, Section 34: SW/4SW/4, W/2SE/4SW/4
- Approximately 760 Acres

To maintain these mineral rights Anfield must comply with the state lease provisions including annual payments with respect to State of Utah leases ML 49310, and ML 53604.

4.3 Permitting

4.3.1 Velvet-Wood Permitting

Permitting for Velvet-Wood mining operations requires various approvals from the state of Utah Division of Oil, Gas and Mining (DOGM) and the US Bureau of Land Management (BLM). There is an existing Large Mine permit for the Velvet Mine which will need to be updated and revised. Refer to Section 20.

4.3.2 Slick Rock Permitting

Exploration and mining activities for the mining claims of the Slick Rock project are administrated by the Durango, Colorado BLM field office. Exploration drilling and associated activities require an exploration permit and a reclamation bond that must be posted with the State of Colorado, Department of Natural Resources Division of Reclamation, Mining, and Safety. At the time of the report, Anfield does not possess an exploration permit nor has a reclamation bond been posted.

4.3.3 Shootaring Canyon Mill Permitting

The Shootaring Canyon Mill has a radioactive source materials license which will need to be amended to allow mill operations to resume, as discussed in Section 20.

4.4 Environmental Liabilities

4.4.1 Velvet-Wood and Shootaring Canyon Mill Environmental Liabilities

Financial assurance instruments are required by Utah for the mine and exploration permits. There are currently two bonds in place for the Velvet-Wood Project. The first is associated with the Large Mining Operation Permit in the amount of $52,274.20 relating to the Velvet Mine. The second is associated with a Notice of Intent to Conduct Exploration in the amount of $17,770.00 related to the combined Velvet-Wood Project. The current surety bond for the Shootaring Canyon Mill totals $12,294,452.00.

No other outstanding environmental liabilities are known to the authors.

4.4.2 Slick Rock Environmental Liabilities

Anfield is unaware of any significant environmental liabilities on the property. DOE also maintains a legacy site within the property boundary. No exploration, development, or mining may take place within or below the DOE legacy site.

4.5 State and Local Taxes and Royalties

4.5.1 Velvet-Wood and Shootaring Canyon Mill Taxes and Royalties

Uranium mining in Utah is subject to Mineral Production Tax. Mineral Production Tax Withholding was increased from 4% to its current level of 5% effective July 1, 1993. (Refer to Utah Senate Bill 180, 1993). On the Section 2 State of Utah lease, an 8% royalty is levied on uranium, and a 4% royalty applies to vanadium production or other minerals. Additional state taxes would include property and sales taxes. At the federal level, profit from mining ventures is taxable at corporate income tax rates. However, for mineral properties depletion tax credits are available on a cost or percentage basis, whichever is greater. For uranium, the percentage depletion tax credit is 22%, among the highest for mineral commodities. (See IRS Pub. 535).

The estate of Mr. Jim Butt holds a 2.5% gross production royalty on all uranium and vanadium recovered at the Shootaring Canyon Mill from material mined from the Velvet 1-9 claims. Mr. Kelly Dearth holds a 1% gross royalty for all uranium mined from the Wood claims, including UT 31-38, 41-44, 48, 50, 52, 54-72, and 129, a total of 37 claims.

4.5.2 Slick Rock Taxes and Royalties

Uranium mining in Colorado is subject to Minerals Severance Tax of 2.25% after the first $19 million of gross product. In addition, two claim blocks are associated with royalties of 1% related to the Holley BC claims and 3% associated with the MCT claims. At the federal level, profit from mining ventures is taxable at corporate income tax rates. However, for mineral properties depletion tax credits are available on a cost or percentage basis whichever is greater. For uranium, the percentage depletion tax credit is 22%, among the highest for mineral commodities. (See IRS Pub. 535).

4.6 Encumbrances and Risks

To the authors' knowledge there are no other forms of encumbrance related to the Project. The Velvet project has an existing mine permit, and the Shootaring Canyon Mill has a radioactive source materials license. There is no permit on the Slick Rock or Wood mine area. Both mines and the mill have operated in the past. As discussed in Section 20, there are existing reclamation/closure requirements and bonds associated with these permits and licenses. The Project does have some risks similar in nature to other mining projects in general and uranium mining projects specifically, i.e., risks common to mining projects as discussed in Section 25.

To the authors' knowledge there are no other significant factors that may affect access, title, or the right or ability to perform work on the property if the aforementioned requirements, payments, and notifications are met.

Section 5: Accessibility, Climate, Local Resources, Infrastructure, and Physiography

5.1 Physiographic Features

5.1.1 Velvet-Wood Physiographic Features

The Velvet-Wood Uranium Project is located within the Lisbon Valley physiographic province in San Juan County, Utah. The project area is located primarily on a dipping bench above the Lisbon Valley, with elevations averaging 6,750 feet above sea level. Nearly 500 feet of elevation differential exists between the highest and lowest drill hole collars on the property. The site is located overlooking the Lisbon Valley. The Lisbon Valley drains through the Little Indian Canyon into Colorado where it joins the Dolores River, which enters the Colorado River northeast of Moab.

5.1.2 Slick Rock Physiographic Features

The Slick Rock property is located in the southern end of the Uravan mineral belt of the Colorado Plateau physiographic province. It is located in the southeastern edge of the Paradox fold and fault belt in the proximal Disappointment syncline. Elevations within the project area range from approximately 5,500 feet to 6,250 feet above sea level. The majority of the project area lies within the broad Disappointment Valley floor. It is bounded on the west by the Dolores River and incised to the west and south by Burro Canyon, Joe Davis Canyon, and Nicholas Wash. To the north is a dip-slope of an escarpment formed from erosion of the northern limb of the Disappointment Valley syncline.

5.2 Access

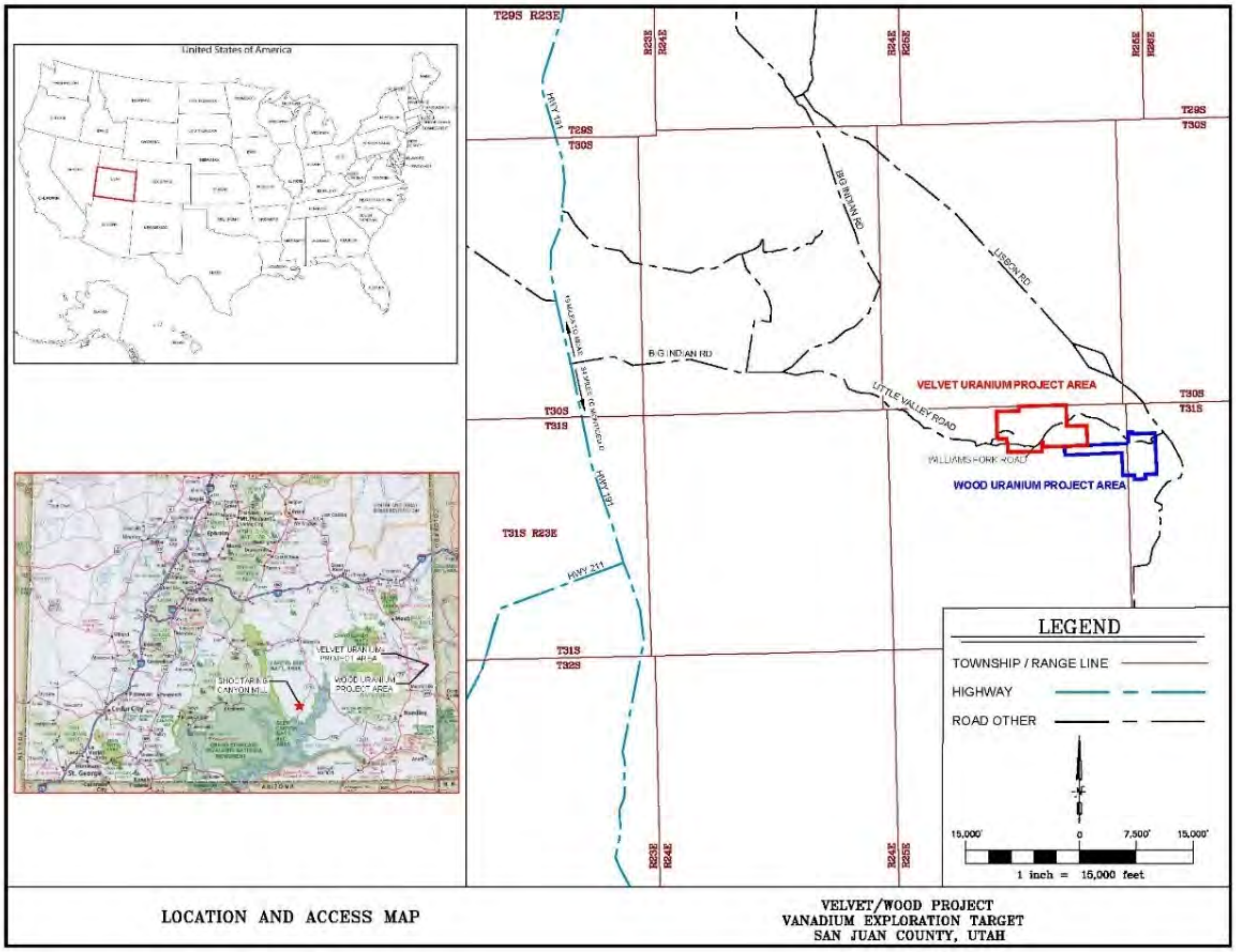
5.2.1 Velvet-Wood Access

Portions of the Velvet deposit were previously mined. Mineralization was accessed via a portal and decline. The mine entrance has been closed by backfill. However, in the authors' opinion the decline could be re-opened. The Velvet portal is accessible by good quality roads beginning with the Big Indian Road, a hard surface road that exits U.S. Highway 191 about 19 miles north of Monticello, Utah or 34 miles south of Moab, Utah (See Figure 5.3).

The Big Indian Road extends eastward and loops into the Lisbon Road to serve properties in the Lisbon Valley area. A gravel road, San Juan County Road 112 (Williams Fork) exits the Big Indian Road about 5.5 miles east of its intersection with Highway 191. A private access road connects with County Road 112 about 6 miles southeast of its intersection with the Big Indian Road. The Velvet Mine portal is about one mile northeast along this road. The site, as described above, is accessible via 2-wheel drive on existing county and/or two-track roads. The project is located approximately 10 miles south of La Sal, Utah. Most transport will occur via over-the-road commercial trucks. Access to exploratory drill sites and vent locations are provided by existing roads connecting to the main access at the Velvet portal and the Lisbon Road.

The Wood mine area is located about 3 miles east of Velvet along County Road 112 and is also accessible from the east via the Lisbon Valley Road and County Road 112.

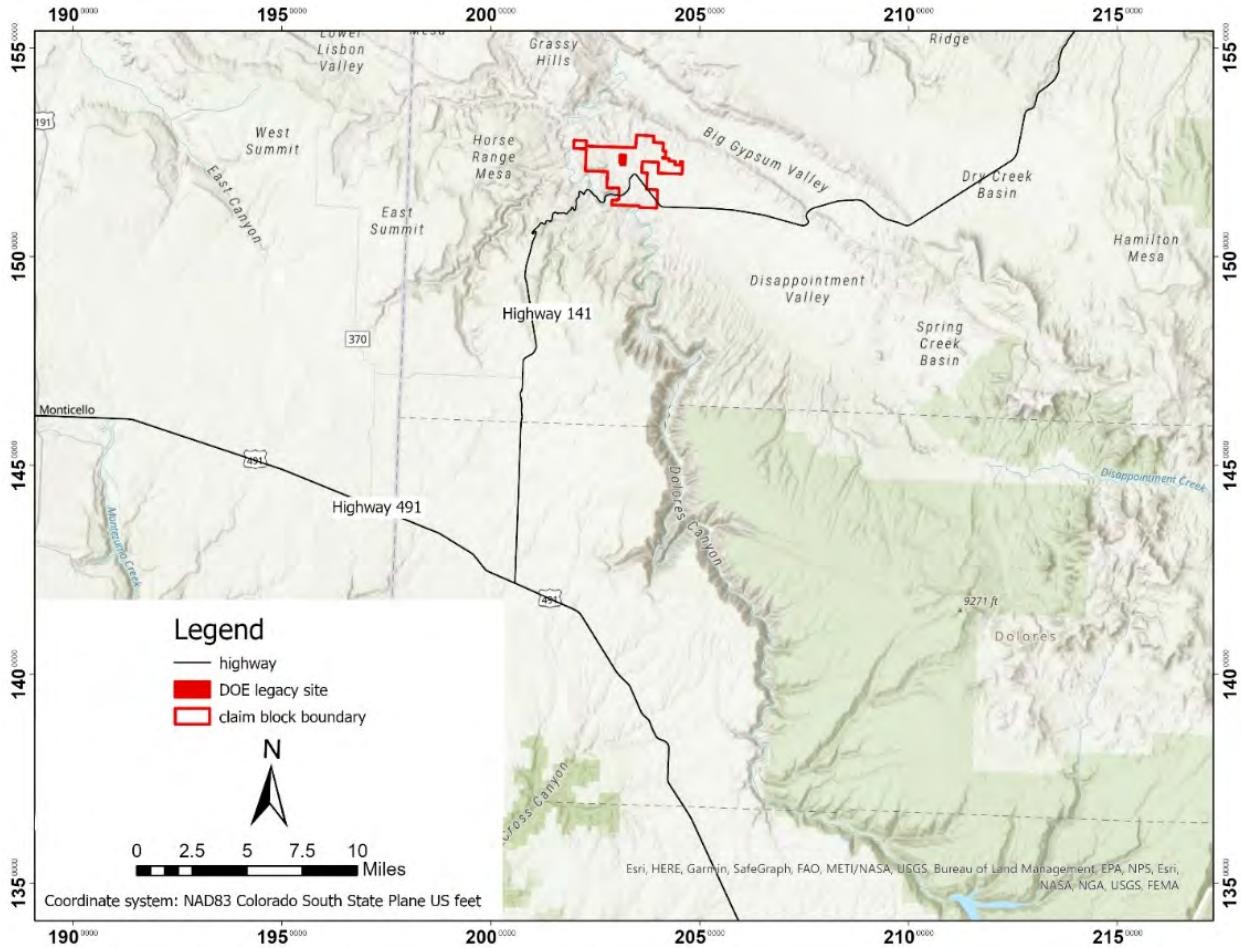
Figure 5.3 - Velvet-Wood Access Map



5.2.2 Slick Rock Access

The Slick Rock project can be accessed via Colorado State Highway 141, County Road CR-T11, and numerous historic drill roads and trails (See Figure 5.4). To access the site: from the post office in Dove Creek, Colorado, drive 2.0 miles west-northwest on State Highway 491; turn right (north) onto State Highway 141; continue for 23.7 miles to County Road CR-T11, and then turn left onto the well-maintained gravel road.

Figure 5.4 - Slick Rock Access Map



5.2.3 Shootaring Canyon Mill Access

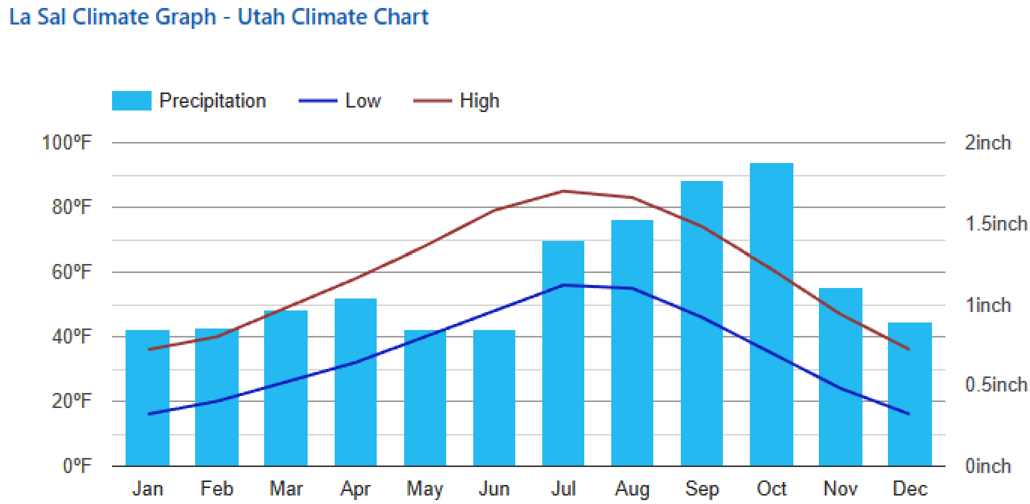
The Shootaring Canyon Mill is located approximately 2 miles west of Utah Highway 276 and approximately 3 miles north of Ticaboo, Utah as shown in Figure 1.1. By road it is approximately 180 miles from the mill to the Velvet Mine area. Access to the mill is via paved highways with the exception of the 2-mile gravel road from the mill to Highway 276.

5.3 Climate

5.3.1 Velvet-Wood Climate

The climate is semi-arid. Average temperatures in July range from a high of 85ºF and a low of 56ºF. The average temperatures in January range from a high of 36ºF and a low of 16ºF. The average annual precipitation is thirteen inches. Winters are generally mild, and the length of the operating season should not be affected by the climate. A climate summary follows.

Figure 5.1 - Velvet-Wood Climate Summary

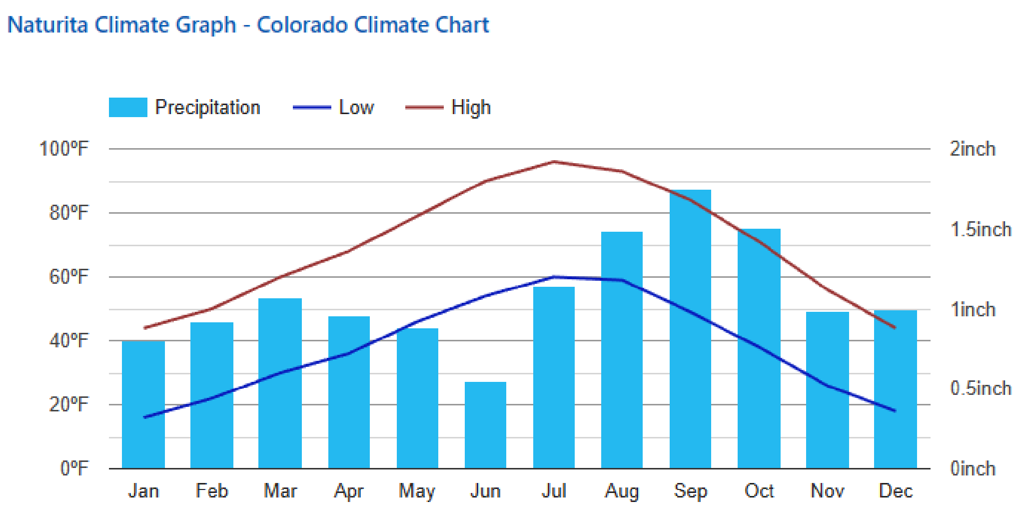


(https://www.usclimatedata.com/climate/la-sal/utah/united-states/usut0134#geo_map)

5.3.2 Slick Rock Climate

The climate is semi-arid and is characterized by mild winters with moderate snowfalls which are seldom heavy enough to cause access problems. The summers are warm with temperatures occasionally reaching 100°F. Annual precipitation for the area averages approximately 12 inches occurring mostly during summer thunderstorms; the remaining precipitation comes from winter snow and spring rain. Climate is only a minimally limiting factor for year-round mining operations. Vegetation in the area is sparse and consists of junipers and pinion pines in rocky soils along with sage and other brush, forbs, grasses, and cacti typical of a semi-arid climate.

Figure 5.2 - Slick Rock Climate Summary

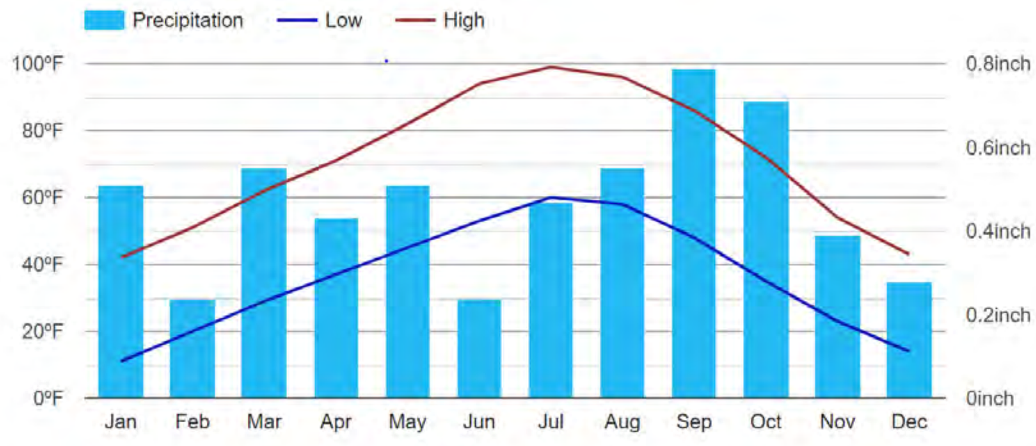


(https://www.usclimatedata.com/climate/naturita/colorado/united-states/usco0651)

5.3.3 Shootaring Canyon Mill Climate

The climate is arid. Average temperatures in July range from a high of 99ºF and a low of 60ºF. The average temperatures in January range from a high of 42ºF and a low of 11ºF. The average annual precipitation is less than 6 inches. Winters are generally mild, and the length of the operating season should not be affected by the climate. A climate summary follows.

Figure 5.3 - Shootaring Canyon Mill Climate Summary



(https://www.usclimatedata.com/climate/hanksville/utah/united-states/usut0101)

5.4 Property Infrastructure

5.4.1 Velvet-Wood Infrastructure

The Velvet-Wood Mine is located between Monticello, Moab, and La Sal, Utah. In addition to access roads, some infrastructure is present on the Velvet-Wood site. The site is accessible over the multiple historic drill trails covering the area. An active copper mine, Lisbon Valley Copper Mine, is located 3 air miles north of the property. The presence of the copper mine and other industrial facilities in the area is significant in context of mine permitting, in that the Velvet-Wood Mine will be compatible with current land use. A power line terminates within 1mile of the old Velvet Mine portal, which is located in the SE ¼ of Section 3, T31S, R25E. Water for industrial use has been previously supplied by wells. Two of the previous underground mine ventilation shafts have been capped with access for water sampling retained. A third vent shaft has been reclaimed at the surface.

5.4.2 Slick Rock Infrastructure

Cortez, Colorado (population 8,500) is the nearest major community, located approximately 57 miles south-southeast from the Slick Rock project area. It has sufficient services, fuel, accommodations, and supplies to serve as a staging area for any future exploration program.

The Slick Rock project area has multiple access roads in addition to overhead power lines and a buried natural gas line. A ventilation shaft exists on site to the Burro underground mine. The shaft has been grated and is open. The Burro portal and underground mine workings are open and ground conditions are stable on an adjacent property. It is possible that an agreement to access the

Slick Rock Mineralization from the Burro underground could be negotiated but was not considered for the purposes of this report and the preliminary economic analysis.

5.4.2 Shootaring Canyon Mill Infrastructure

The Shootaring Canyon Mill infrastructure is discussed in Sections 17 and 18.

5.5 Land Use

5.5.1 Velvet-Wood Land Use

The Velvet-Wood project area is generally used for livestock grazing and recreational uses such as hunting. An active copper mine and heap leach facility, the Lisbon Valley Copper Mine, is located 3 air miles north of the property. The presence of the copper mine and other industrial facilities in the area is significant in the context of mine permitting in that the Velvet-Wood project will be compatible with current land use.

5.5.2 Slick Rock Land Use

The Slick Rock project area is generally used for livestock grazing and recreational uses such as hunting. Historic mining occurred in the area including the neighboring Burro and Ellison Mines. A legacy Department of Energy site is centrally located within the site.

5.5.3 Shootaring Canyon Land Use

The Shootaring Canyon mill is an existing mineral processing facility that is located on private land with no public access.

5.6 Flora and Fauna

All of the project areas are arid or semi-arid areas with little to no vegetation. Vegetation at Velvet-Wood is characteristically pinion, cedar, and juniper forest, with some ponderosas in the higher areas. Slick Rock and the Shootaring Canyon Mill site are sparsely vegetated. Bare rock with sparse vegetation such as yucca is common, and sagebrush is thick in drainages where soil forms. Common mammals include the desert cottontail, squirrels, and mule deer. Common birds include jays, ravens, golden eagles, and hawks. There are also a variety of reptiles including lizards and snakes.

5.7 Surface Rights and Local Resources

5.7.1 Velvet-Wood Surface Rights

The Velvet-Wood mining claims are on public lands; the surface and mineral rights are administered by the BLM. The Mining Law of 1872 provides for surface rights associated with mining claims provided the use and occupancy of the public lands in association with the development of locatable mineral deposits is reasonably incident including prospecting, mining, or processing operations and is approved by the appropriate BLM Field Office; see 43 CFR Subpart 3715. The state lease has similar provisions for surface use.

5.7.2 Slick Rock Surface Rights

The 1872 Mining Law grants certain surface rights to mineral claimants along with the right to mine provided the surface use is incident to the mine operations. In order to exercise those rights, the operator must comply with a variety of State and Federal regulations (refer to section 20.1). For the mine operations, as described in Section 16, the author concludes that Anfield has and/or can obtain sufficient surface rights for the planned operations through permitting and licensing of site activities.

5.7.3 Shootaring Canyon Surface Rights

The surface leases associated with the mill convey the necessary rights for operation of the mill and associated tailings facility provided all environmental regulations and license conditions are met.

Section 6: History

6.1 Project History

6.1.1 Velvet-Wood Project History

The original locator of the Velvet area of the project was Gulf Minerals Corporation (Gulf). The Velvet Mine Uranium Project was initially drilled during the 1970s with the principal exploratory work and drilling completed by Gulf.

The Wood mineralization was discovered in 1975 by Atlas in Section 6, Township 31 South, Range 26 East (Chenoweth, 1990). Uranerz U.S.A. Inc. (Uranerz) later controlled the Wood area of the project during the 1980s when most of the initial exploration took place. A total of 120 known historic rotary drill holes were completed by Uranerz from 1985 through 1991. The exploration resulted in the discovery of three mineralized zones in the Cutler Formation. The most important of these, the Wood mineralized body, was outlined in 14 holes that intercepted high grade material. Sometime in the 1990s, Uranerz's mining claims were allowed to lapse.

Gulf sold the Velvet property to Atlas in the late 1970s. Atlas' Velvet Mine commenced operations in 1979 in Section 3 and advanced to the property line with Section 2. Atlas completed feasibility studies for mining the Section 2 mineral resources including hoisting and haulage of mined product to their Moab mill for processing in 1980. These plans were never executed due to low uranium prices in the 1980s, and the Section 2 property was sold by Atlas Minerals as they were experiencing an economic downturn. The Velvet Mine was closed in 1984. Subsequent changes in ownership include:

- The Velvet Mine property was acquired by Umetco Minerals Corp. in 1989.
- Umetco held the Section 3 property until the mid-1990s at which time the property was transferred to US Energy (USE).
- Mr. William Sheriff secured the Section 2 state lease by competitive bid and staked the adjoining mining claims. The property was then transferred to Energy Metals Corporation (EMC).
- In 2004, Energy Metals Corporation staked new mining claims over the Wood area.
- Uranium One gained control of the Velvet-Wood property through the purchase of Energy Metals Corporation in 2007.

As discussed in Section 4.2, Anfield purchased the Velvet-Wood Uranium Project and other conventional uranium assets including the Shootaring Canyon Mill located near Ticaboo, Utah from Uranium One in August 2015.

6.1.2 Slick Rock Project History

Surficial to shallow uranium/vanadium mineralization has been known in the Slick Rock area since the early 1900s, originally known as the McIntyre district. First mined for radium and minor uranium until 1923, numerous companies sporadically operated small scale mining and processing facilities along the Dolores River. In 1931, a mill was constructed by Shattuck Chemical Co. to process vanadium ore. Beginning in 1944, the area was worked by Union Mines Development Corp. for uranium/vanadium ore. The uranium was used to develop and construct the first atomic bombs. This sparked intensive exploration efforts throughout the Uravan mineral belt.

Between November 1948 and March 1956, the USGS drilled 2,641 holes in the Slick Rock district to explore for uranium- and vanadium-bearing deposits. The drilling was part of an exploration program conducted for the U.S. Atomic Energy Commission (OFR70-348). Fifty-two of these drill holes were located within the boundary of Anfield's Slick Rock project area. The first phase of the USGS's exploration was to obtain geological data and delineate areas of favorable ground. This widely spaced drilling program was done on approximately 1,000 foot centers. The second phase was drilled with more moderate spacing (100-300 foot centers) to discover ore deposits. The third phase was drilled on more closely spaced intervals (50-100 foot centers) to extend and outline any deposits discovered by earlier drilling (Weir, 1952). At this time, private industry was also actively exploring the area. By 1954, an estimated 212,000 feet of drilling was completed district wide (Shawe, 2011).

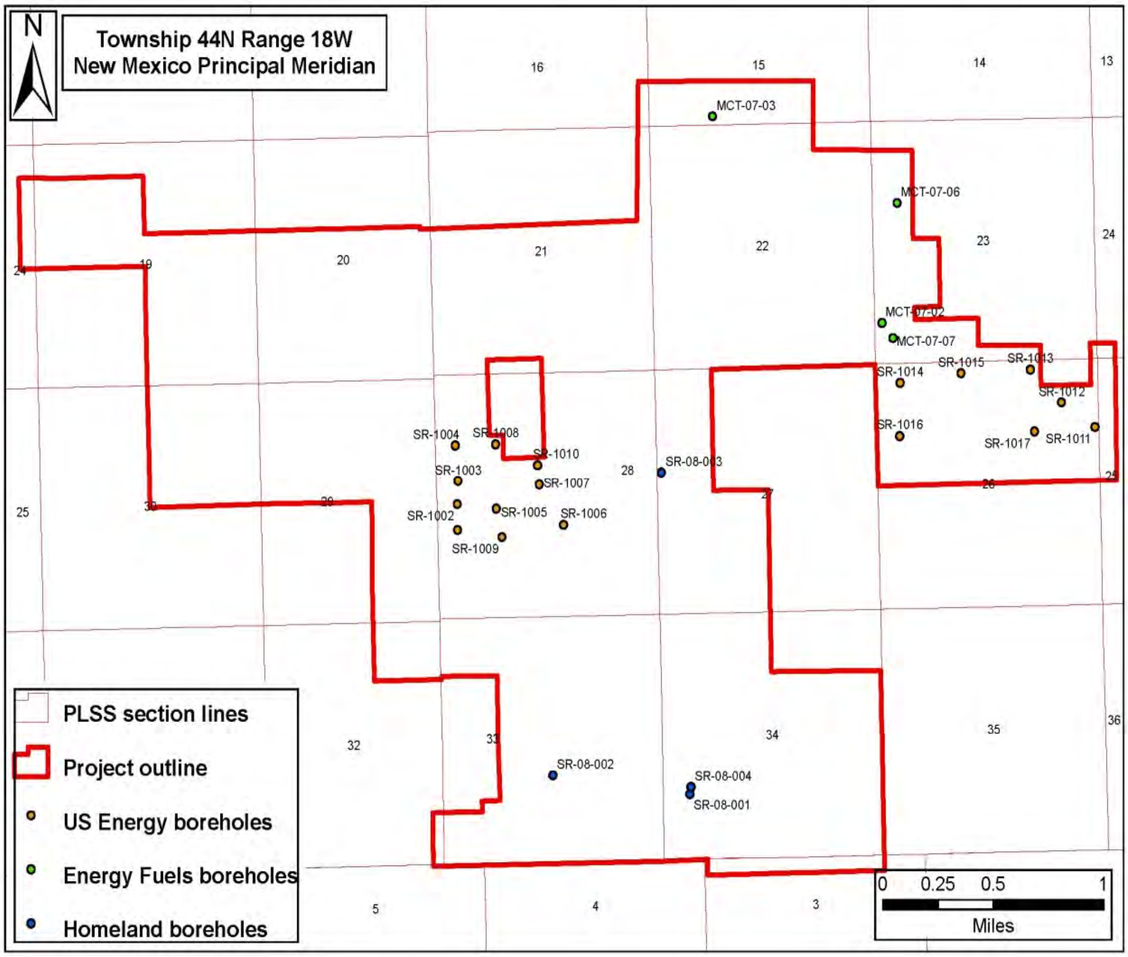
By December 1955, Union Carbide Nuclear Corp. (UCNC) had drilled out a sufficient resource on the north side of Burro Canyon and began sinking three shafts. In December 1957, the shaft sinking was complete on the Burro No. 3, 5, and 7 mines to total depths of 408 feet, 414 feet, and 474 feet, respectively. In the same year, initial ore shipments to UCNC's concentrating mill at Slick Rock were also made. The concentrated ore was processed at the UCNC mill in Rifle, Colorado until the mid-1960s when a vanadium circuit was constructed at the Uravan mill site.

The Anfield Slick Rock project has received more recent interest by the exploration activities of USEC, Energy Fuels, and Homeland Uranium. In 2006, USEC drilled 17 boreholes. All boreholes were completed to target depth, except one borehole SR-1011 which was abandoned.

In 2007, Energy Fuels drilled five boreholes on the extreme northern portion of the project. Four of the boreholes were oxidized and barren. The fifth borehole was abandoned due to excessive water encountered in the Burro Canyon Formation and the upper Salt Wash Member of the Morrison Formation (Bill Thompson, Manager, Ur-Energy, LLC).

In 2008, Homeland Uranium drilled four boreholes in an attempt to twin the mineralized boreholes drilled by the AEC in the 1950s. All boreholes were completed to target depth.

Figure 6.1 - 2006-2008 Borehole Map



UEC began acquiring mineral interests in the Slick Rock project area beginning in December of 2010 by staking areas where the previous owner had allowed the mining claims to lapse. UEC then held 293 mineral lode claims encompassing an area of approximately 4,858.5 acres. UEC also began leasing additional claims from UR Energy on November 30, 2011. Anfield acquired all of UEC's Slickrock holdings including claims and claims leases on April 12, 2022, as part of the overall acquisition agreement as described in Section 6.1.1.

6.1.3 Shootaring Canyon Mill Ownership History

The Shootaring Canyon Mill was licensed and constructed by Plateau Resources and has had a succession of owners including US Energy and Uranium One prior to Anfield.

On August 27, 2015 Anfield closed the Asset Purchase Agreement (APA) with Uranium One Americas Inc. ("Uranium One") and subsequently amended to acquire the Shootaring Canyon Mill located in Utah and a portfolio of conventional uranium mine assets as described in Section 6.1.1.

6.2 Previous Mineral Resource Estimates

6.2.1 Velvet-Wood Historic Mineral Resource Estimates

A historic mineral resource estimate for the Velvet area within Section 2 was completed by MRC using a polygonal method. A similar historical mineral resource estimate for the Velvet area within Section 3 was completed by Price, 1987. Mineral resources related to the Wood area, located in T31S, R26E, Section 7, is referenced in the literature (Chenoweth, 1990). However, the original source and basis of this estimate is not known and thus cannot be stated herein.

Section 14 provides a current estimate of mineral resources in accordance with National Instrument 43-101.

6.2.2 Slick Rock Historic Mineral Resource Estimates

There are no historical mineral resource estimates for Slick Rock known to the authors.

6.3 Past Production

6.3.1 Velvet-Wood Past Production

The Velvet Mine operated into the early 1980s. According to Chenowith, due to continued low uranium prices, Atlas Minerals closed all of their mines and mill, which included the Velvet in southeastern Lisbon Valley in March 1984. When the Velvet mine was closed it had produced approximately 400,000 tons of ore which graded 0.46 percent U_3O_8 and 0.64 percent V_2O_5 with total production estimated at 4.2 million pounds of U_3O_8 (Chenoweth 1990).

6.3.2 Slick Rock Past Production

In 1971, the final year that the Atomic Energy Commission reported production figures, the Burro mines had produced 404,804 tons of ore at an average grade of 0.25% U_3O_8 yielding 1,992,898 lbs U_3O_8, and 1.5% average grade V_2O_5 yielding 12,149,659 lbs V_2O_5 (Nelson-Moore et al., 1978). According to the Colorado Bureau of Mines' annual reports, the Burro mines produced an additional 243,825 lbs U_3O_8 at an average grade of 0.20% and 1,791,798 lbs V_2O_5 at an average grade of 1.4% up until 1983 when depressed uranium prices forced an end to mining activities. The total production of the Burro mines was 2,236,723 lbs U_3O_8 and 13,941,457 lbs V_2O_5 as summarized in Table 6.2.

Table 6.2 - Slick Rock District Total Production

Production Years	U_3O_8 (lbs)	V_2O_5 (lbs)
1957-1971	1,992,898	12,149,659
1971-1983	243,825	1,791,798
Total	2,236,723	13,941,457

Section 7: Geological Setting and Mineralization

7.1 Regional Geological Setting: The Colorado Plateau

The Colorado Plateau is a regional geologic feature characterized by high elevation mesas and deeply incised canyons in southwestern Colorado and much of eastern Utah. The sedimentary units which dominate the Colorado Plateau were deposited during a period of tectonic stability beginning in the early Paleozoic and running through the Mesozoic Eras. During this time, a stable shelf depositional environment allowed thick accumulations of clastic, carbonate, and evaporitic sediments. Beginning approximately 6 million years ago, the entire Colorado Plateau was subject to epeirogenic uplift of 4,000-6,000 feet. This geologically rapid uplift caused the existing rivers and streams to aggressively downcut resulting in the canyon lands topography of today (Hunt, 1956). The Velvet-Wood and Slick Rock projects are both situated in the central portion of the Colorado Plateau. The Velvet-Wood lies along the western flank of the Lisbon Valley anticline in the Lisbon Valley Utah while Slick Rock Project is located along the spine of the Disappointment syncline in the Paradox Basin of Colorado.

Sedimentary strata within the Colorado Plateau hosts numerous uranium/vanadium deposits. Uranium deposits are hosted by the Pennsylvanian Hermosa Formation, the Permian Cutler Formation, the Triassic Chinle Formation, and the Jurassic Morrison Formation as shown on the stratigraphic description in Table 7.1. The majority of the uranium production in the Colorado Plateau was from the Morrison Formation, specifically the Salt Wash Member. In the Salt Wash Member, deposits are concentrated along a thin, one to several mile-wide arcuate belt that extends from the Gateway district through the Uravan district and south to the Slick Rock district. This concentration of deposits was termed the Uravan mineral belt as shown on Figure 7.1 (Fischer and Hilpert, 1952). This crescent-shaped area in the Jurassic Morrison formation has closely spaced, larger-sized, and higher-grade uranium deposits than the adjoining areas.

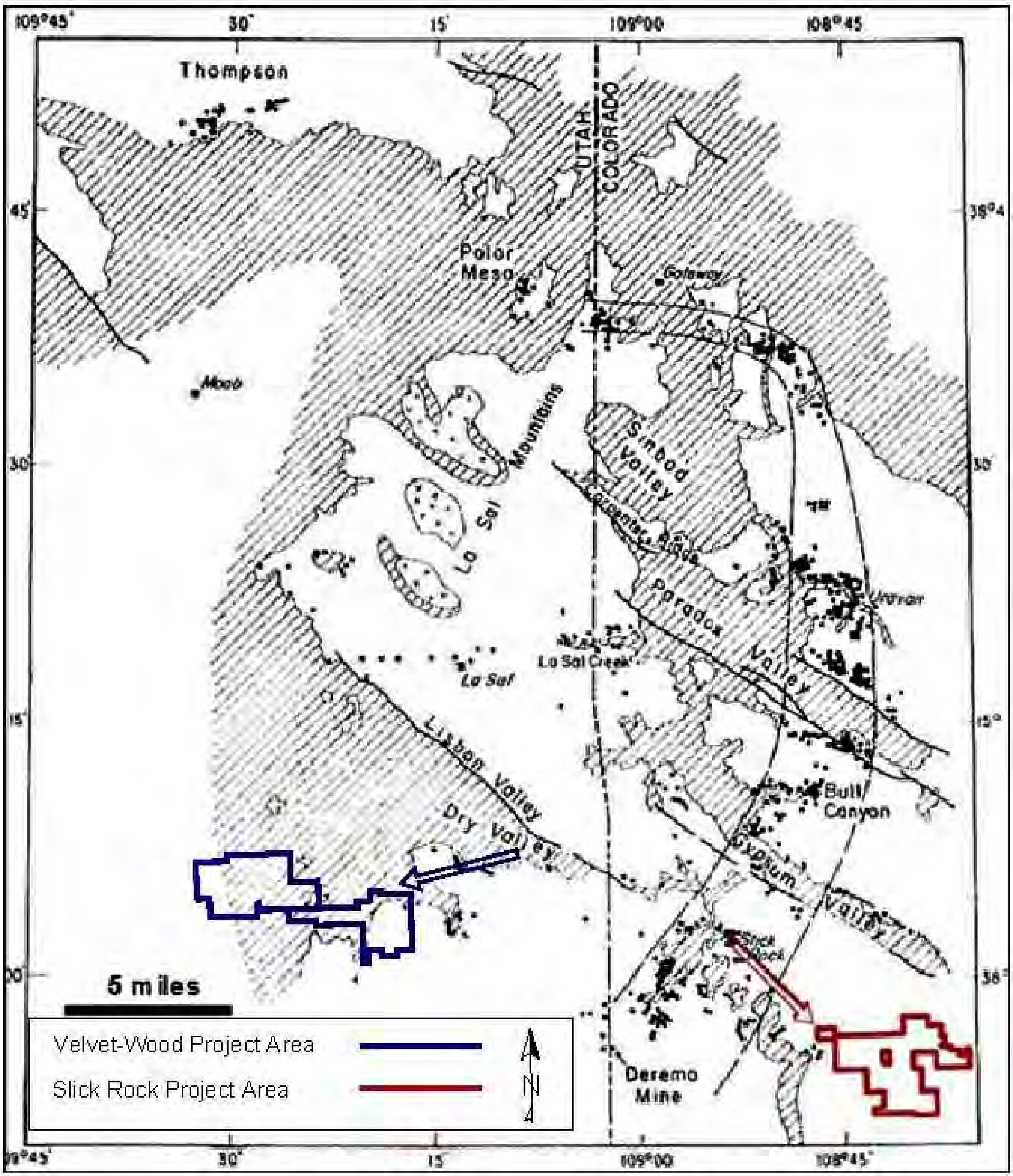
Slick Rock lies within the southern half of Uravan Mineral Belt which has been a historically significant producer of uranium and vanadium since the early 20th century. The Lisbon Valley anticline along which the Velvet-Wood project is located is the most productive uranium producing area in Utah (Chenoweth, 1990). Among the rock units exposed along the Lisbon Valley Anticline, those that contain documented uranium mineralization are the Permian Cutler Formation, the Triassic Chinle Formation (Moss Back Member) and the Morrison Formation (Salt Wash Member). Both projects have significant adjacent and adjoining uranium and vanadium production histories, as discussed in Section 6, History.

Table 7.1 - Stratigraphy of Slick Rock District and Vicinity (Shawe, 1970)

TABLE 1.—*Summary of consolidated sedimentary rocks in the Slick Rock district*

Age	Formation and member	Thickness (feet)	Description
Late Cretaceous	Mancos Shale	1, 600–2, 300	Dark-gray carbonaceous, calcareous shale.
	Dakota Sandstone	120–180	Light-buff sandstone and conglomeratic sandstone, dark-gray carbonaceous shale, and coal.
Early Cretaceous	Burro Canyon Formation	40–400	Light-gray to light-buff sandstone and conglomeratic sandstone; greenish-gray and gray shale, siltstone, limestone, and chert.
Late Jurassic	Morrison Formation, Brushy Basin Member	300–700	Reddish-brown and greenish-gray mudstone, siltstone, sandstone, and conglomerate.
	Morrison Formation, Salt Wash Member	275–400	Light-reddish-brown, light-buff, and light-gray sandstone and reddish-brown mudstone.
	Junction Creek Sandstone	20–150	Light-buff sandstone.
	Summerville Formation	80–160	Reddish-brown siltstone and sandstone.
	Entrada Sandstone, Slick Rock Member	70–120	Light-buff to light-reddish-brown sandstone.
	Entrada Sandstone, Dewey Bridge Member	20–35	Reddish-brown silty sandstone.
Jurassic and Triassic(?)	Navajo Sandstone	0–420	Light-buff and light-reddish-brown sandstone.
Late Triassic(?)	Kayenta Formation	160–200	Purplish-gray to purplish-red siltstone, sandstone, shale, mudstone, and congolmerate.
Late Triassic	Wingate Sandstone	200–400	Light-buff and light-reddish-brown sandstone.
	Chinle Formation, Church Rock Member	340–500	Reddish-brown, purplish-brown, and orangish-brown sandstone, siltstone, and mudstone; dark-greenish-gray conglomerate.
	Chinle Formation, Petrified Forest(?) Member	0–100	Greenish-gray mudstone, siltstone, shale, sandstone, and conglomerate.
	Chinle Formation, Moss Back Member.	20–75	Light-greenish-gray and gray sandstone and conglomerate; minor greenish-gray and reddish-brown mudstone, siltstone, and shale.
Middle(?) and Early Triassic	Moenkopi Formation	0–200	Light-reddish-brown siltstone and sandy siltstone.
Early Permian	Cutler Formation	1, 500–3, 000	Reddish-brown, orangish-brown, and light-buff sandstone, siltstone, mudstone, and shale.
Late and Middle Pennsylvanian	Rico Formation	130–240	Transitional between Cutler and Hermosa Formations.
Middle Pennsylvanian	Hermosa Formation, upper limestone member	1, 000–1, 800	Light- to dark-gray limestone; gray, greenish-gray, and reddish-gray shale and sandstone.
	Hermosa Formation, Paradox Member	3, 250–4, 850	Upper and lower units gray dolomite, limestone, and dark-gray shale interbedded with evaporites; middle unit halite and minor gypsum, anyhdrite, dolomite, limestone, and black shale.
	Hermosa Formation, lower limestone member	100–150	Medium-gray limestone, dark-gray shale.
Early Pennsylvanian and Mississippian	Molas Formation	100	Reddish-brown, dark-gray, and greenish-gray shale and silty shale and gray limestone.
Mississippian	Leadville Limestone	240	Medium-gray limestone and dolomite.
Devonian	Name not assigned	250–550	Gray sandy dolomite and limestone and grayish-green and reddish sandy shale.
Cambrian	Name not assigned	500–700	Light-gray to pinkish conglomeratic sandstone, sandstone, siltstone, shale, and dolomite.
Precambrian	Name not assigned	--------------	Granitic to amphibolitic gneisses and schists, and granite.

Figure 7.1 - Uravan Mineral Belt (adopted from Chenoweth, 1981)



7.2 Velvet-Wood Project Local Geology

The dominant feature in the Velvet-Wood area is the Lisbon Valley Anticline. The Lisbon Valley Anticline is a northwest/southeast feature about 20 miles long that was formed when salt in the Paradox Formation was mobilized. The up-warping and subsequent erosion of the anticline has exposed Pennsylvanian to Cretaceous age rocks along the length of the anticline. Consolidated rocks that crop out in the Lisbon Valley area range in age from Late Pennsylvanian to early Pleistocene. The oldest, the Pennsylvanian Honaker Trail Formation, is exposed in the interior of the anticline with successively younger rocks exposed in the faces of three mesas along the flanks of the anticline. In the Velvet-Wood area the mesa recedes southward stepwise away from the center of the anticline and is known as Three Step Hill. The surficial geology of Velvet-Wood is shown on Figure 7.2 and the Regional Cross Section in Figure 7.3.

Figure 7.2 - Velvet-Wood Project Local Geologic Map (from Doelling, 2004)

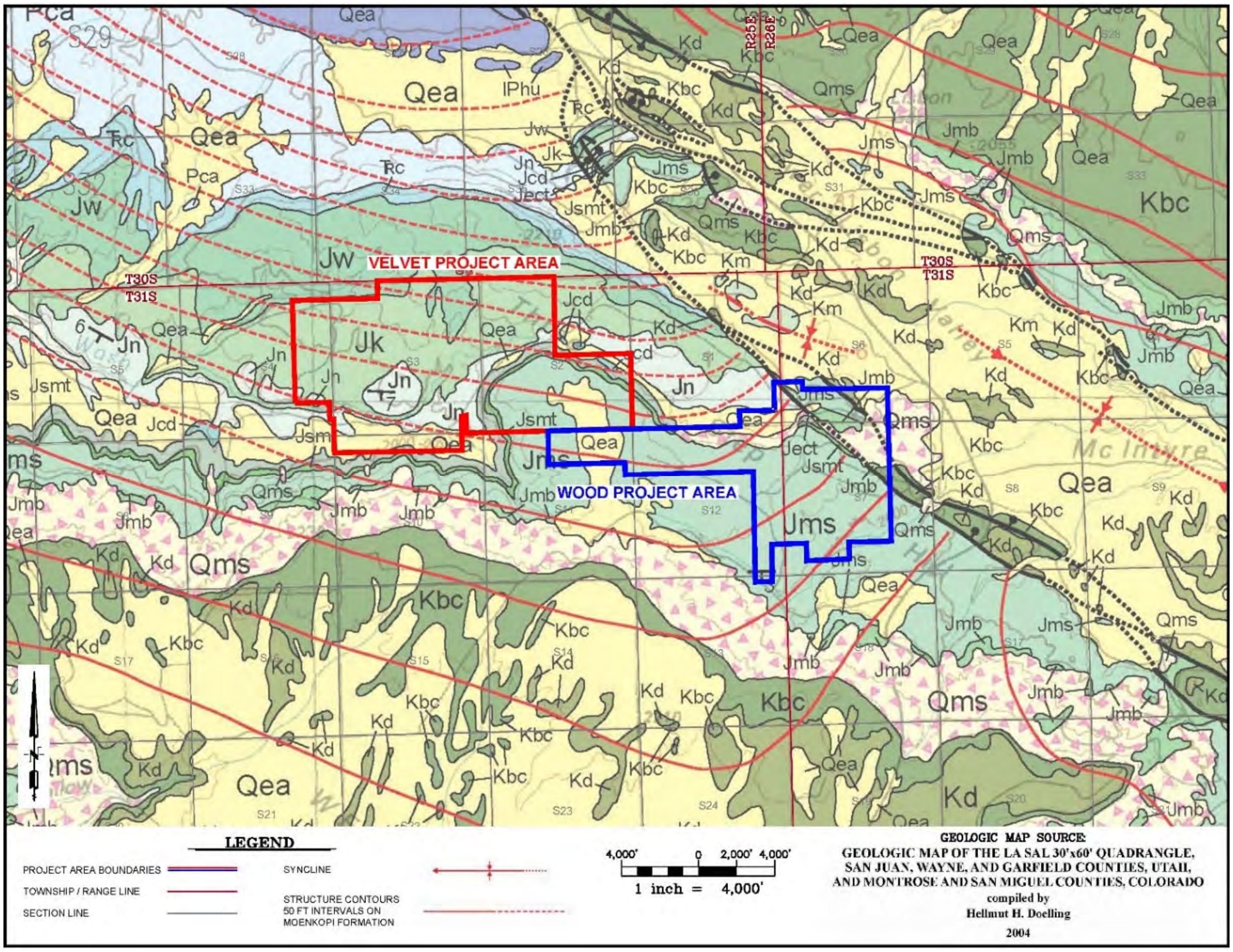
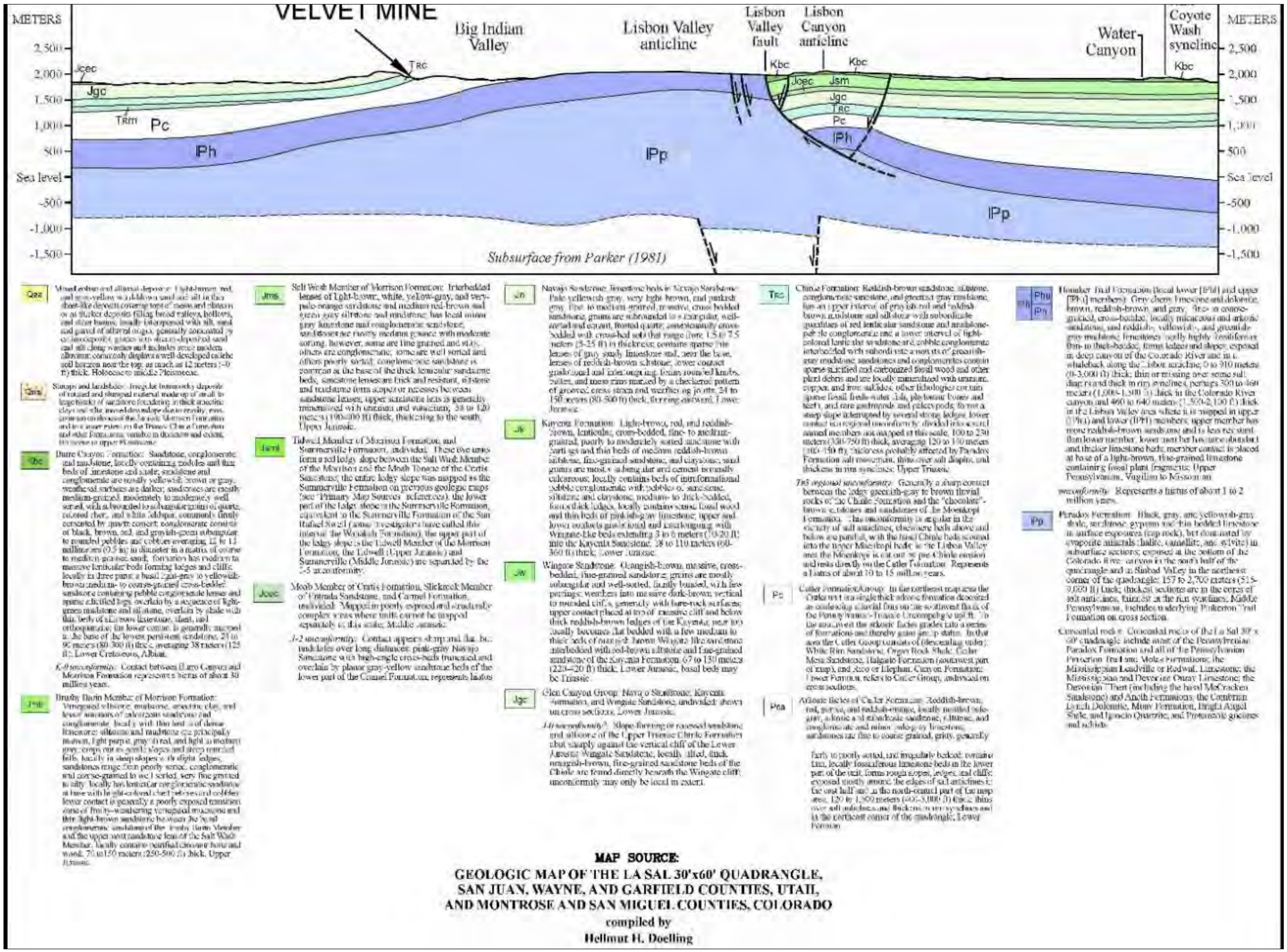


Figure 7.3 - Velvet-Wood Project Regional Cross Section (Doelling, 2004)



Three Step Hill is composed of three mesas, each progressively higher than the last. The Velvet-Wood Deposit is under the lowest mesa and on the margin of the second. The top of the mesa is a dip slope primarily on the top of the Wingate Sandstone. Low mesas of Kayenta Formation rocks are preserved near the southern base of the dip slope. The dip slope of the middle mesa is composed of resistant sandstone units of the Salt Wash Member of the Morrison Formation. The Brushy Basin Member has been stripped off the plateau but is exposed near the base of the slope of the third mesa. The highest mesa is capped by the Burro Canyon Formation. Some remnants of Dakota Sandstone are exposed on the upper plateau. The dips of the rocks are progressively shallower toward the south. The dips on the lower plateau are about 6 to 8 degrees and dips on the upper plateau are about 3 to 5 degrees.

Locally, uranium mineralization is found in the Permian Cutler Formation. The Cutler formation in Lisbon Valley is composed predominantly of fluvial arkosic sandstones, siltstones, shales, and mudstones that were deposited by meandering streams that flowed across a flood plain and tidal flat. This flood plain was occasionally transgressed by a shallow sea from the west, resulting in the deposition of several thin limestones and marine sandstones. Wind transported sand along the shoreline of the shallow sea, forming dunes (Campbell and Mallory, 1979). The marine and eolian sandstones are usually finer grained, better sorted, and cleaner than the fluvial arkosic sandstones. The fluvial sandstones are medium to very coarse grained and have abundant feldspar and biotite. The sandstone units are usually red-brown to purple red in color. Some of the sandstones have been bleached tan to gray-white. The top of the Cutler is truncated by a regional unconformity that has removed in excess of two hundred feet of the formation in the northern part of Lisbon Valley.

The unconformity at the top of the Cutler has truncated the southward dipping Cutler beds, the mineralized sandstone bed at the Velvet-Wood Deposit is stratigraphically a few hundred feet above that at the Big Buck Mine in the northern end of Lisbon Valley. The purple-red fluvial sandstones occur in large lenticular bodies that are hundreds of meters long and range in thickness from less than 3 to over 75 feet. Laterally these lenses thin and grade into the shale, mudstone, and siltstone sequences (Campbell and Mallory, 1979).

The fluvial sandstones are composed of medium to coarse-grained quartz, feldspar, and rock fragments in sub equal amounts. These arkosic sandstone units' source of sediment was the Uncompahgre highland northeast of the Velvet-Wood area on the Utah/Colorado border. The cementing agent in the Cutler fluvial sandstones is either calcite or secondary overgrowth on the quartz grains. All of the known mineralized fluvial sandstone units were bleached light tan-pink or gray-white (Campbell and Mallory, 1979).

The upper portion of the Cutler Formation, which is the primary host of known uranium mineralization in the Velvet-Wood Area, is composed of intervals of siltstone interbedded with thin-bedded, fine-grained sandstone. In places there are thicker, more resistant sandstone beds up to 47 feet thick. The thickness and frequency of sandstone beds increases downward, and siltstone is less common. Thick mudstone intervals separate the sandstone beds. A few limestone and conglomerate beds occur in the bottom third of the formation. The rocks are mostly greenish-gray, reddish-brown, or reddish-orange. The limestone beds are usually olive-gray (Campbell and Mallory, 1979).

Faulting and folding are the major structural features of the Velvet-Wood area. There are two major faults in the Velvet-Wood area. The faults are northeastward dipping normal faults with displacement ranging from a few feet to as much as 700 feet. The rock units between the two faults are folded downward to the northeast. The sandstones in the Velvet-Wood area exhibit jointing parallel to the Lisbon Valley anticline and are thought to be tensional joints. The host rocks of the Velvet-Wood Area are truncated by the faulting on the southwest side of the Lisbon Valley graben. The mineralization of the Velvet-Wood Deposit appears to be fault bounded on the northeast side of the deposit. (Gordon, et al, 1981).

7.2 Slick Rock Project Local Geology

The Slick Rock district lies in the Paradox Basin at the southern edge of the salt anticline region also called the Paradox Fold and Fault Belt (Kelley, 1958). The district, which covers approximately 570 square miles of the Colorado Plateau, is underlain by about 13,000 feet of sedimentary strata which lies on metamorphic and igneous rocks of a Precambrian basement. The sedimentary formations range in age from Cambrian to Late Cretaceous (Shawe, 1970). See Figures 7.4a and 7.4b for Slick Rock Project Local Geology Map.

Figure 7.4a - Geologic Map of Slick Rock Project Area (from USGS/Carter 1955)

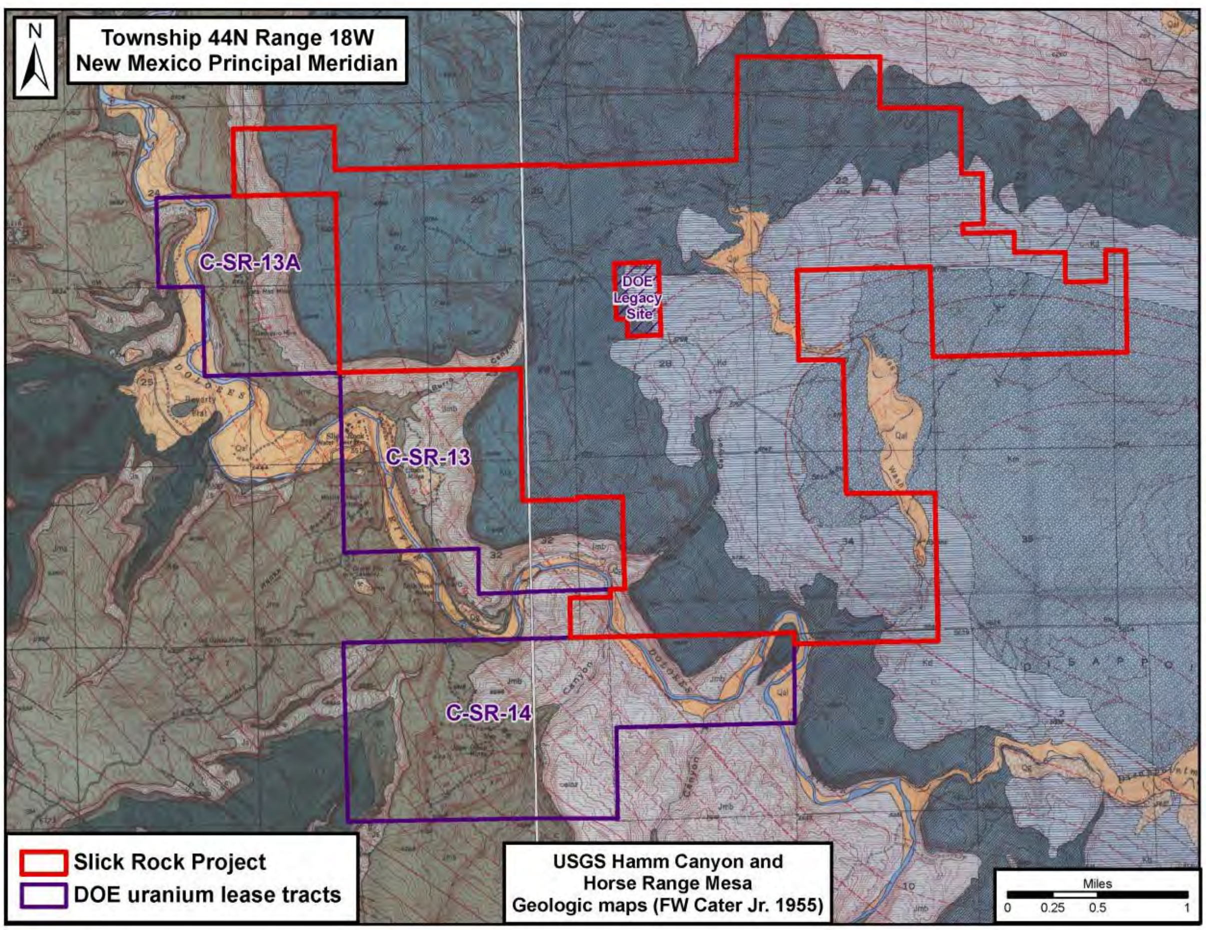
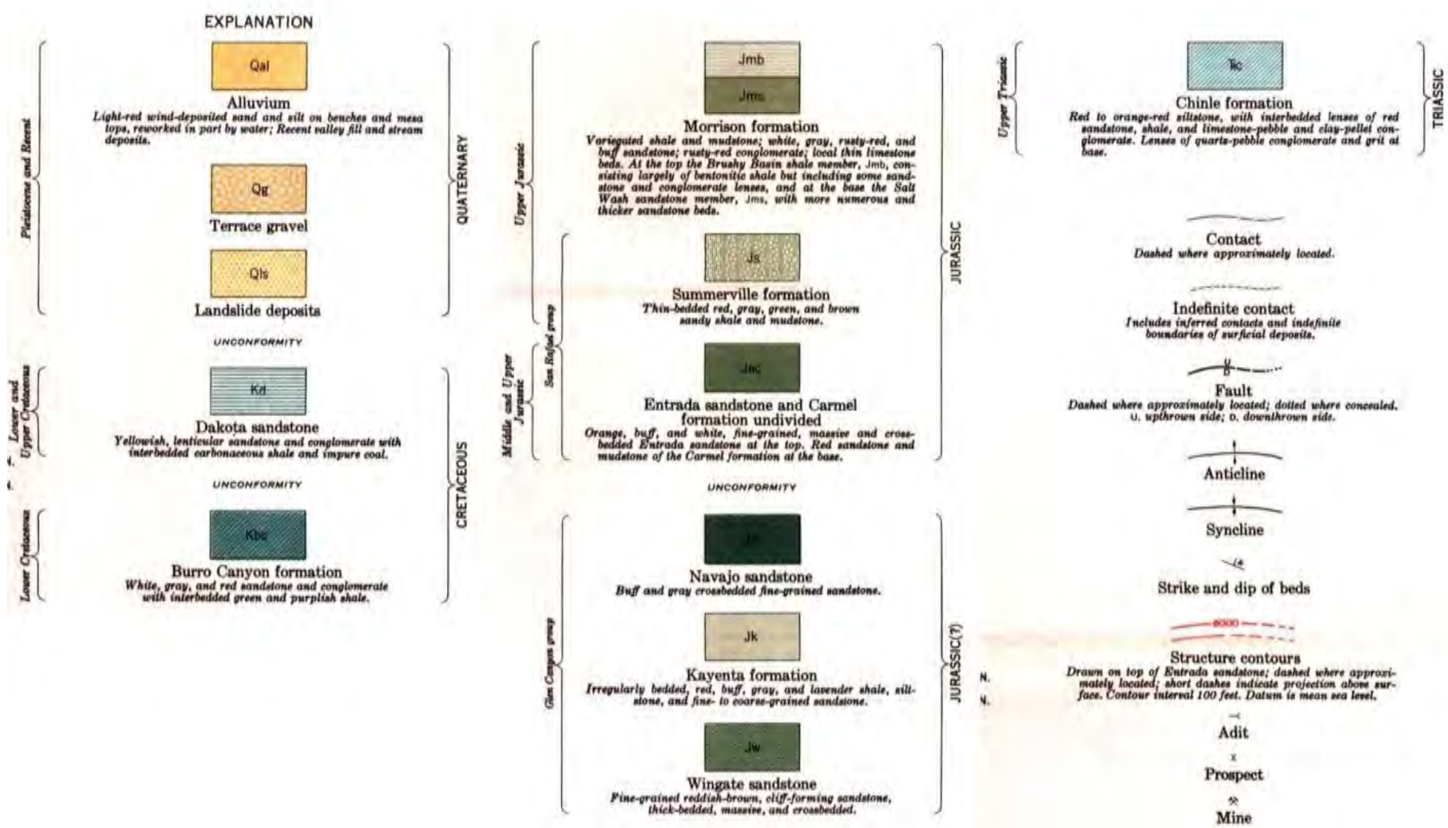


Figure 7.4b - Geologic Map of Slick Rock Project Area Legend (from USGS/Carter 1955)



The Slick Rock project is located in the proximal Disappointment Valley syncline. The syncline plunges gently to the southeast and lies between the collapsed Gypsum Valley anticline to the northeast and the Dolores anticline to the southwest. Sedimentary rocks that outcrop in the Slick Rock district range from the Permian Cutler Formation up to the late Cretaceous Mancos Formation with a maximum thickness of approximately 4,700 feet (Shawe, 2011). The Jurassic Morrison Formation is the host of uranium/vanadium deposits in the Slick Rock district. It is widely recognized as an aggrading, terrigeneous clastic, fan-shaped fluvial sequence of sediments. While the precise location of the sediment source is unknown due to erosion, most authors agree that the sediment source area for the fan is the modern-day south-central Utah and north-central Arizona area (Page et al., 1956). The proximal fan is dominated by a high percentage of coarse clastics in braided stream sediments. The energy of the depositional environment decreases distally, as does the grain size of the sediments. The Slick Rock district occupies the medial fan facies. From the apex of the fan, the stream flow was in a northern, northeastern, and eastern direction. In the Slick Rock district, the direction of stream flow was generally to the northeast while local paleo topography controlled the flow direction.

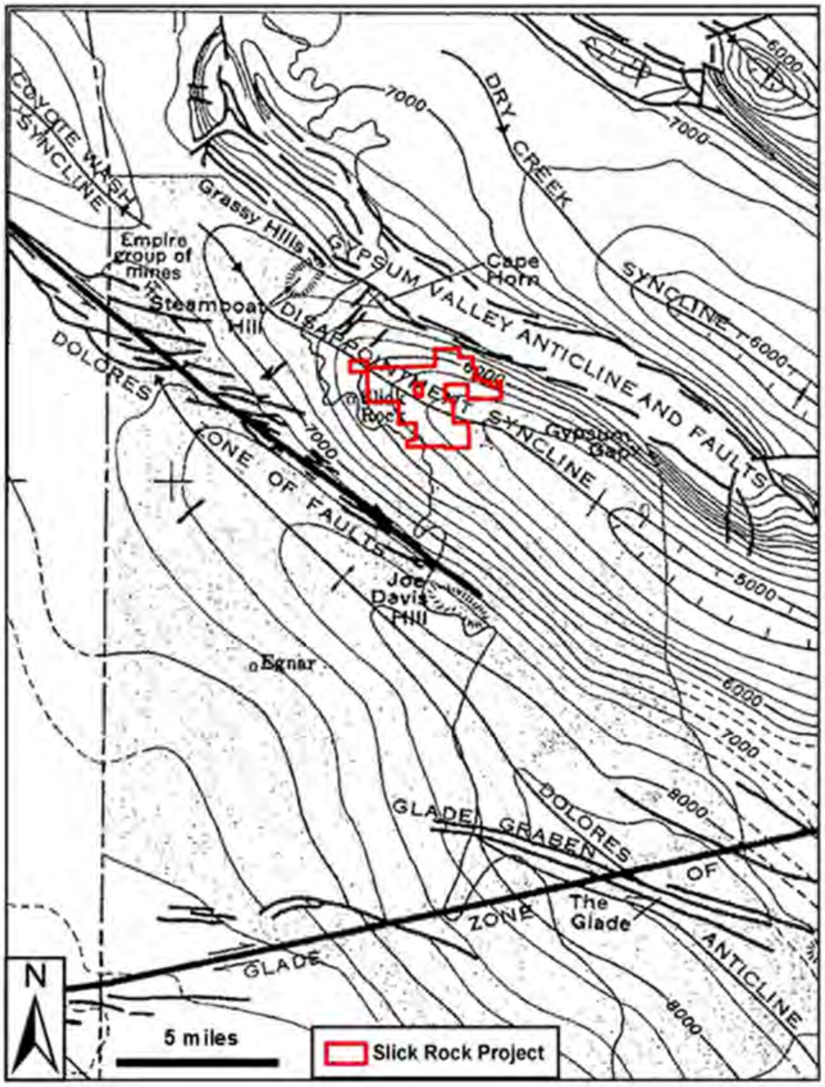
The salt anticlines were the positive topographic highs during Jurassic time that diverted Morrison distributary systems to courses along their flanks. This allowed for thick accumulations of high sandstone/mudstone ratio sediments in valleys that flanked the elongated salt domes of Jurassic time. High sandstone/mudstone ratios increase permeability (the ability of sediments to transmit fluids) and porosity (available void space). Such conditions are favorable for increased fluid flow and may largely control ore formation. The thick accumulation of sediments in major channels occurred along the southern margin of the Gypsum Valley anticline in the Slick Rock district and across Anfield's project area (Tyler and Ethridge, 1983).

Major folds in the Slick Rock district are broad, open, and trend about north 55 degrees west, and are parallel to the collapsed Gypsum Valley salt anticline which bounds the northeast edge of the district. The Dolores anticline lies about ten miles southwest of the Gypsum Valley anticline. The Disappointment syncline lies between the two anticlines (Williams, 1964). See Figure 7.5, Slick Rock Structural Geology Map.

Within the Slick Rock project area, the Morrison is divided into two Members: the upper Brushy Basin Member and the lower Salt Wash Member. The Salt Wash Member is composed of fluvial sandstone and mudstone averaging about 350 feet thick, and is further divided into three parts: the top and bottom units that are composed of fairly continuous layers of sandstone interbedded with thin layers of mudstone, and a middle unit that is primarily mudstone but contains scattered discontinuous lenses of sandstone (Rogers and Shawe, 1962 MF-241).

The Slick Rock district lays in an area where only the Salt Wash and Brushy Basin Members of the Morrison Formation are present. The Morrison Formation attains its maximum thickness in these members and stream-type deposits (lenticular cross-bedded sandstones) have their greatest aggregate thickness and maximum lateral continuity (Shawe, 2011).

Figure 7.5 - Slick Rock Structural Geology Map (from Williams, 1964)



As discussed in Section 6, History, the USGS on behalf of the Raw Materials Division of the Atomic Energy Commission, conducted extensive exploration throughout the Uravan mineral belt. As early as 1952, the USGS had determined that the following four geologic characteristics were indicative of favorable grounds for a uranium deposit:

- Most mineralized deposits are in or near thicker, central parts of sandstone lenses and, in general, the thickness of the sandstone decreases moving away from the mineralized deposits. Sandstone less than 40 feet thick is generally not favorable for large ore bodies.
- Sandstone in the vicinity of the mineralized deposit is colored light brown, but moving away from the mineralized deposit an increasing proportion of sandstone has a reddish color, which is indicative of unfavorable ground.
- The mudstone in the mineralized sandstone near and immediately below the deposit changes from a red to gray color. The amount of altered mudstone decreases further outward from the deposit.

- Sandstone in the immediate vicinity of the deposit contains more carbonized plant fossils than similar beds further away from the mineralized zone. This suggests that mineralization is localized in the vicinity of abundant carbonaceous material (Weir, 1952).

Results from USGS's 1948-1956 drilling indicate that within Anfield's Slick Rock project area the Salt Wash is greater than 40 feet thick, contains abundant carbonaceous material, is tan to gray in color, and is in contact with a reduced mudstone over a significant portion of the project area.

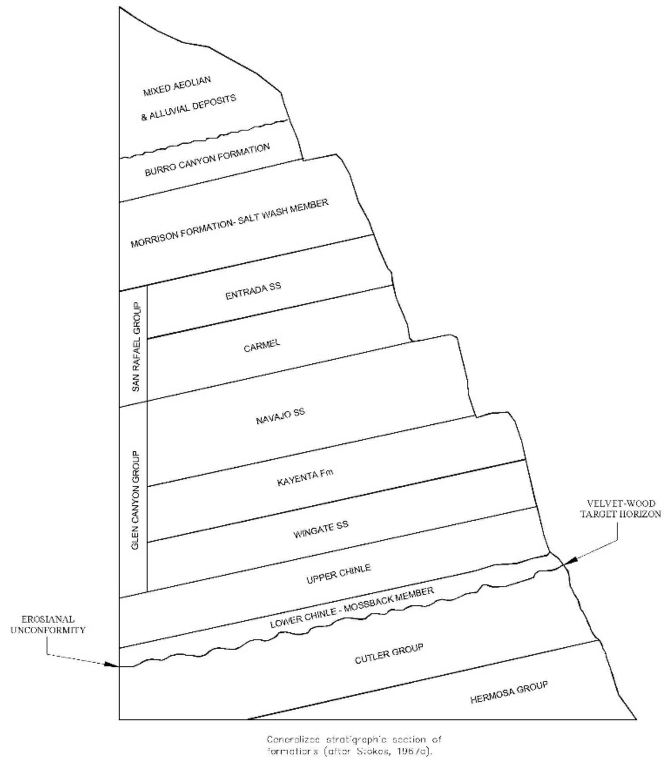
Section 8: Deposit Types

8.1 Velvet-Wood Deposit Type

Uranium mineralization in the Velvet and Wood areas is found in sandstone units within the Cutler Formation. The sandstones are fluvial arkose that has been bleached. The mineral deposits are irregular tabular bodies (Denis, 1982) located at the base, at the top, or close to pinch-outs of the sandstone bodies (Campbell and Mallory, 1979). The major producing zone in the Cutler occurs near the unconformity between the Cutler and the overlying Chinle Formation. The mineralization may extend a short distance into the sandstone of the Moss Back above. The uranium-bearing sandstones are petrologically very similar to other Cutler fluvial sandstones but contain less calcite and more clay and are slightly coarser grained (Campbell and Mallory, 1979). Uraninite is the principal uranium mineral encountered in the reduced zones of the Velvet Area. In areas where the mineralization lies above groundwater levels, oxidized uranium minerals such as carnotite and tyuyamunite may occur. Uranium mineralization within the Colorado Plateau of Southwestern Colorado and Southeastern Utah have been described as tabular-blanket type deposits that are sub-parallel to bedding planes and/or features such as unconformities. Mineralization is often confined to paleochannels and controlled by lithology, permeability, porosity, and the presence of a chemical reductant, often carbonaceous material (Hasan, 1986). A similar depositional morphology is observed at the Wood Mine.

Uranium mineral resources within and in the vicinity of the project are found in the upper Permian Cutler formation. Many of the other mines in the district were located in the basal Moss Back member of the Triassic Age Chinle Formation overlying the Cutler Formation. As shown on Figure 8.1, Velvet-Wood Project Stratigraphic Column, there is an erosional unconformity between the Permian and Triassic aged beds where the Triassic Moenkopi formation was eroded away before the placement of the Moss Back Member of the Chinle Formation. Observations from the 2007 and 2008 coring program on the Velvet project has developed the model that mineralization in both formations is related to the unconformity, although the location of mineralization with respect to the contact varies from location to location within the district. Most of the mineral resources in the Cutler occur within six feet of the unconformity.

Figure 8.1 - Velvet-Wood Project Stratigraphic Column (Chenowith, 1990)



Much of the historic mining in the vicinity such as the Bardon, Divide, School Section, Pats, and Service Berry mines are pre-1960 except for the Velvet Mine (1979-1984). With the exception of the Velvet and Bardon mines, most of these are in the Chinle formation and were mined prior to 1941. The discovery of mineralization in the Cutler formation was late, therefore the Cutler is largely unexplored (Chenoweth, 1990). Most of the earlier drilling stopped at the base of the Chinle. Further to the east, the discovery of the Wood Deposit was reported by Uranerz in 1987 in T31S, R26E, Section 7 (Chenoweth, 1990). The Bardon, Velvet and Wood mines are oriented along a common trend beginning in the northwest at the Bardon Mine and proceeding to the southeast through the Velvet Mine to the Wood Mine along a trend of more than 6 miles. Limited exploration has been conducted between the Velvet Mine and Wood area, and the Bardon Mine and the Velvet Mine, but these areas remain largely unexplored. The reader is cautioned that additional drilling may or may not result in discovery of additional mineral resources on the property.

8.2 Slick Rock Deposit Type

There has been much discussion and debate regarding ore forming mechanisms in the Slick Rock area, but there is good agreement on several contributing factors:

The Brushy Basin and Salt Wash members contain significant concentrations of detrital volcanic debris which is strongly suspected as the source of uranium and vanadium.

Compaction and de-watering during burial of these sediments allowed for the transport mechanism along preferential pathways dictated by permeability and porosity within transmissive sand units of the Morrison Formation.

The uranium and vanadium in solution within a transmissive sand unit encountered a reduced environment locally caused by abundant plant remains and evidenced by reduced green mudstone found within the Salt Wash sandstones. This environment favored precipitation of uranium along a solution interface between the uranium in an oxidized alkaline solution and a strongly reduced acidic environment.

The physical expressions of the deposits formed at the solution interface have a variety of shapes and volumes. In the following, Shawe provides an excellent summary of the deposit morphology in the Slick Rock district:

Two general forms of ore bodies are common in the Morrison Formation in the district, one tabular and the other so-called “roll”. Some deposits consist mainly of tabular ore bodies and others are dominantly of roll bodies, although both types display elements of the other, and in many places tabular bodies are continuous with roll bodies. Some deposits have both types significantly developed. The two types were deposited by the same general process and at the same time; differences in their forms were dictated by local differences in the lithology of the host sandstone units that controlled fluid movement (Shawe, 2011).

In the Slick Rock district, uranium/vanadium deposits of the Morrison are mainly tabular to lenticular and elongate parallel to sedimentary trends. Tabular trends are localized in massive sandstones where clay and mudstone are interstitial, in scattered and streaked gall and pebble accumulations, and are found in discontinuous lenses. Conversely, roll deposits are narrow, elongate, and curve sharply across bedding and appear to be confined to sandstone where clay and mudstone are well indurated within interconnected layers. Mineralization in either case, tabular or roll deposits, averages about 0.25% U_3O_8 and 1.5% V_2O_5 within the mineralized sandstone. The mineralized bodies have an average thickness of 2 to 4 feet and range in size from a few feet wide to several hundred feet wide (Fischer and Hilbert, 1952). These deposits can contain a few tons of ore to several thousand tons in the larger ore bodies.

Details of the forms of roll ore bodies related to lithologic differences and mineral distribution within rolls (calcium-carbonate, titanium oxides, barite, and iron oxides) provide strong evidence that the deposition of the mineralized bodies occurred at an interface between two chemically differing solutions (one that is oxidized and one that is reduced). The interface interpretation was first proposed by Fischer in 1942. Continuity of the roll ore bodies with tabular bodies indicate that the tabular bodies also formed at a solution interface. It is important to note that the term “roll” was coined by local miners to describe the geometry of ore bodies that cut across sedimentary bedding and does not imply similarity to the geochemical process involved in forming the “roll” deposits of Wyoming and South Texas uranium provinces, as illustrated in Figures 8.2a and 8.2b, (Shawe, 2011).

Figure 8.2a - Uranium/Vanadium Deposits of the Slick Rock District, Colorado

Perspective Geologic Cross Section of Roll Ore Bodies (Shawe, 2011, paper 576-f)

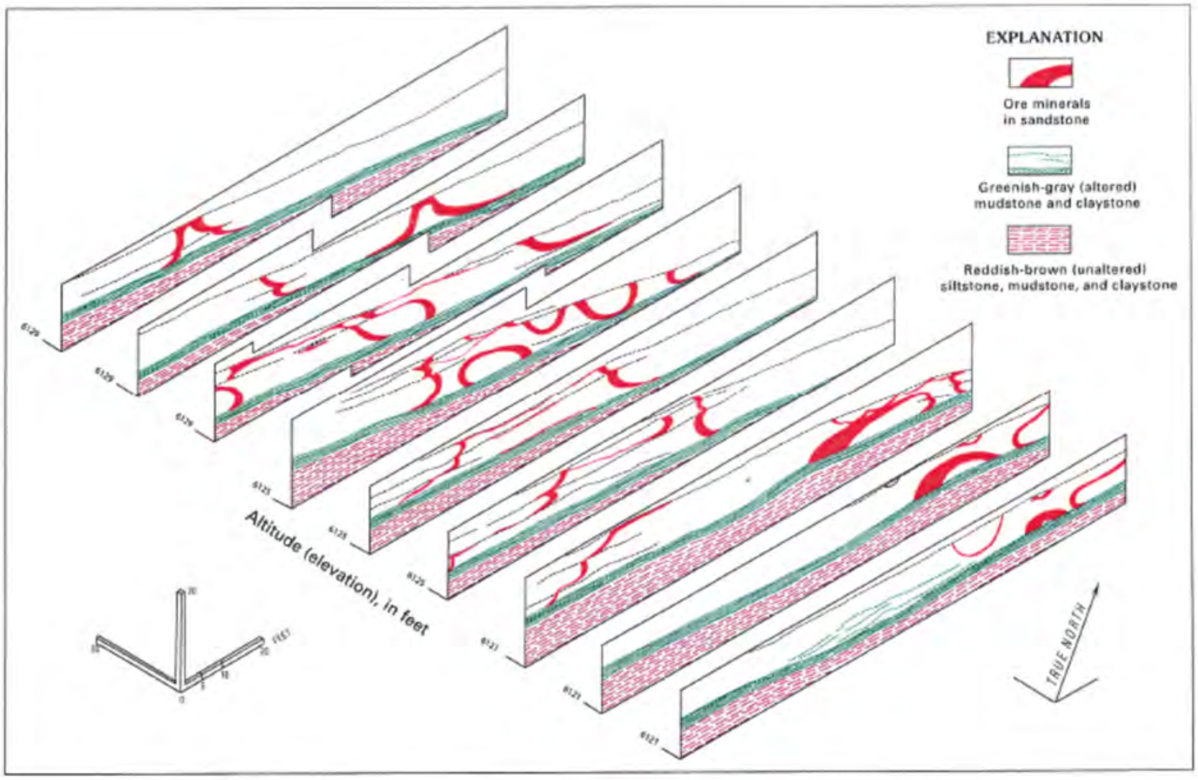
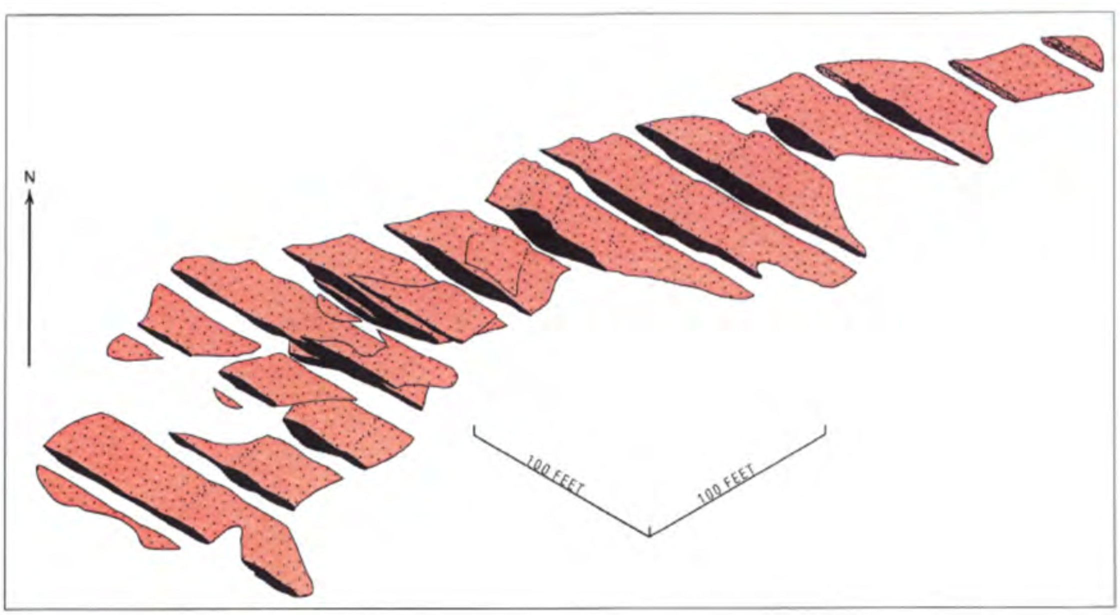


Figure 8.2b - Uranium/Vanadium Deposits of the Slick Rock District, Colorado

Perspective Geologic Cross Section of Tabular Ore Bodies (Shawe, 2011, paper 576-f)



The uranium- and vanadium-bearing minerals occur as fine-grained coatings in detrital grains; they fill pore spaces between the sand grains and replace carbonaceous material and some detrital grains (Weeks et al., 1956). The primary uranium minerals are uraninite (UO_2) with minor amounts of coffinite ($USiO_4OH$). Montroseite (VOOH) is the primary vanadium mineral, along with vanadium clays and hydromica. Metal sulfides occur in trace amounts. Secondary minerals: calcium uranyl vanadate (Tyuyamunite) ($Ca(UO_2)_2(VO_4)_2 \cdot (5\text{-}8)H_2O$) and potassium uranyl vanadate (Carnotite) ($K_2(UO_2)_2(VO_4)_2 \cdot 1\text{-}3H_2O$) occur in shallow oxidized areas and on outcrop. Figure 8.3 shows a typical specimen of oxidized uranium/vanadium minerals collected underground in the vicinity of the Burro No. 3 shaft and the scintillometer.

Figure 8.3 – Slick Rock Sample and Scintillometer

Section 9: Exploration

Anfield has not conducted exploration within or near either the Velvet-Wood or Slick Rock mine areas.

In the late 1940s and through the1950s, extensive exploration was conducted by the US Atomic Energy Commission (AEC) and private parties throughout the region during the Manhattan Project. These programs consisted of geologic mapping, ground and aerial radiometric surveys, trenching, and rock and sediment sampling. Subsequently exploration has been primarily limited to drilling.

Section 10: Drilling

10.1 Drill Summary

Anfield has not conducted drilling on either the Velvet-Wood or Slick Rock projects. A summary of the drill data acquired by Anfield from previous operators follows.

10.2.1 Velvet-Wood Drilling

Atlas and MRC conducted extensive rotary and limited core drilling on the Velvet Mine area that was included in the acquisition of the property, including the delineation of 4 mineralized areas with drilling on a rough grid approximating 100 foot centers.

The available drill data for the Velvet Mine project area includes radiometric data from some 173 drill holes completed on the property. From 1985 through 1991, Uranerz completed a total of 120 known historic vertical rotary drill holes in the Wood Mine project area. There are geophysical logs available for 96 of those historic drill holes. Of the 96 logs, 95 of the historic geophysical logs typically consist of natural gamma, resistivity, spontaneous potential (SP), half foot radiometric grade of uranium measured in weight percent U_3O_8, and vertical deviation data which were matched with a northing and easting collar location and collar elevation from available drill hole maps. All geophysical logging was performed by Century Geophysical Corporation for Uranerz. Industry standard practice for Century Geophysical logging trucks included calibration of the logging trucks routinely at Department of Energy facilities.

Drilling averaged a depth of 1,538 feet and ranged from 1,240 feet to 1,870 feet. All of the holes were surveyed for down-hole deviation, and deviation data was available from the geophysical logs. Drift at the mineralization horizon ranged from 5 feet to over 258 feet and averaged 63 feet to the northeast, or up dip. The dip of the host formation is approximately 8 degrees to the southeast. Drilling was conducted vertically although virtually all drill holes drifted up dip. The average vertical declination was approximately 2.3 degrees from vertical. Because this declination opposed the dip of the formation, the effect of dip on true thickness is diminished. Considering the effect of the actual drill hole declination from vertical, the correction to true thickness would be less. This means that a 10-foot thickness interpreted from the geophysical log would actually be 9.99 feet. At this level, the data correction would be less than the accuracy of the original data, which is interpreted down to one foot. As a result, no correction is necessary from the log thickness to true thickness.

Additional exploration drilling was conducted by Uranium One in 2008, generally focused between the areas of known mineralization at Velvet and Wood. The drilling showed low grade mineralization but did not encounter significant mineralization. In total, Uranium One completed 43 drill holes at Velvet and 14 drill holes at Wood. Locations of all known drill holes are shown on Figure 10.1. Drilling results for the Velvet-Wood project are summarized in Tables 10.1 through 10.3 which follow. Note values are expressed as Grade Thickness (GT), the product of average grade ($\%eU_3O_8$) x thickness (feet).

Table 10.1 - Historic Drill Results Velvet Area*

Barren	Trace < 0.1 GT	Mineralized 0.1–0.25 GT	Mineralized 0.25-0.5 GT	Mineralized > 0.5 GT	TOTAL
6	30	29	24	84	173
3.5 %	17.3 %	16.8 %	13.9 %	48.6 %	

Table 10.2 - Historic Drill Results Wood Area*

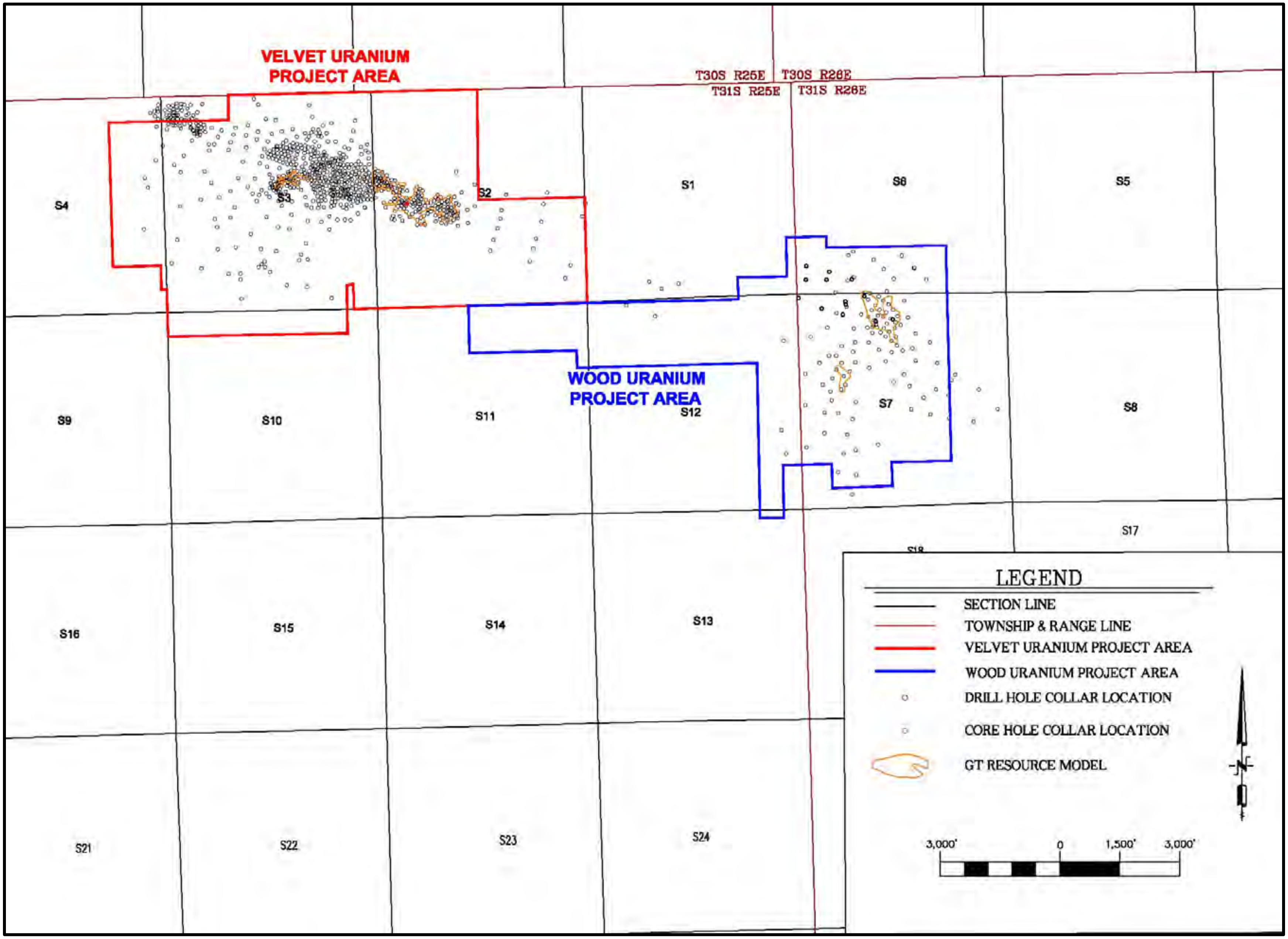
Incomplete	Barren	Trace < 0.1 GT	Mineralized 0.1–0.25 GT	Mineralized 0.25-0.5 GT	Mineralized > 0.5 GT	TOTAL
1	20	40	7	6	21	95
1.1 %	21.1 %	42.1 %	7.4 %	6.3 %	22.1 %	

*The historic data available for Velvet was limited to data from the previous MRC mineral holdings. The historic data available for Wood was from the previous Uranerz mineral holdings.

Table 10.3 - 2007/2008 Drill Results Velvet-Wood

Incomplete	Barren	Trace < 0.1 GT	Mineralized 0.1–0.25 GT	Mineralized 0.25-0.5 GT	Mineralized > 0.5 GT	TOTAL
3	15	20	6	7	6	57
5%	26%	35%	11%	12%	11%	

Figure 10.1 - Velvet-Wood Drill Hole Map



10.2.2 Slick Rock

Anfield has not conducted any exploration drilling on the Slick Rock project. Anfield has obtained radiometric and chemical assays and from U.S. Atomic Energy Commission's exploration program OFR70-348 for vanadium and uranium values, respectively, from those holes drilled by the USGS on behalf of the Raw Materials Division of the AEC. Logs for boreholes drilled by USEC and Energy Fuels were obtained by claim acquisition, and the uranium intercept values from the logs for boreholes drilled by Homeland Uranium were available in the public domain.

A total of 312 holes are known to be contained within or proximal to the Slick Rock project area. Of that total, 27 of these holes had locations but no other data leaving 285 drill holes upon which to build a database. Of the 285 holes in the database used for resource estimation, 207 were drilled by Union Carbide, 53 by the USGS, 17 by USEC and 4 each by Energy Fuels and Homeland Uranium. Within the 285 drill holes data was available on 346 discrete intercepts distributed between 3 stratigraphically distinct zones.

Mineralization at Slick Rock occurs within three stratigraphic horizons of the Jurassic Morison Formation. Three-Dimensional Plotting and correlation of the Slick Rock intercept demonstrated three vertically distinct mineralized zones running along dipping bedding. The A zone is stratigraphically the youngest and highest in the section, followed by the B zone and then the deepest C zone. A summary of drill results follows in Table 10.4. Drill hole locations are shown on Figure 10.2.

Table 10.4 - Slick Rock Drill Hole Intercepts by Zone

	Intercepts in database	Composited Intercepts	Composited Intercepts above 0.02 % eU_3O_8
Zone A	109	46	13
Zone B	214	129	67
Zone C	23	6	3

Figure 10.2 - Slick Rock Drill Hole Map

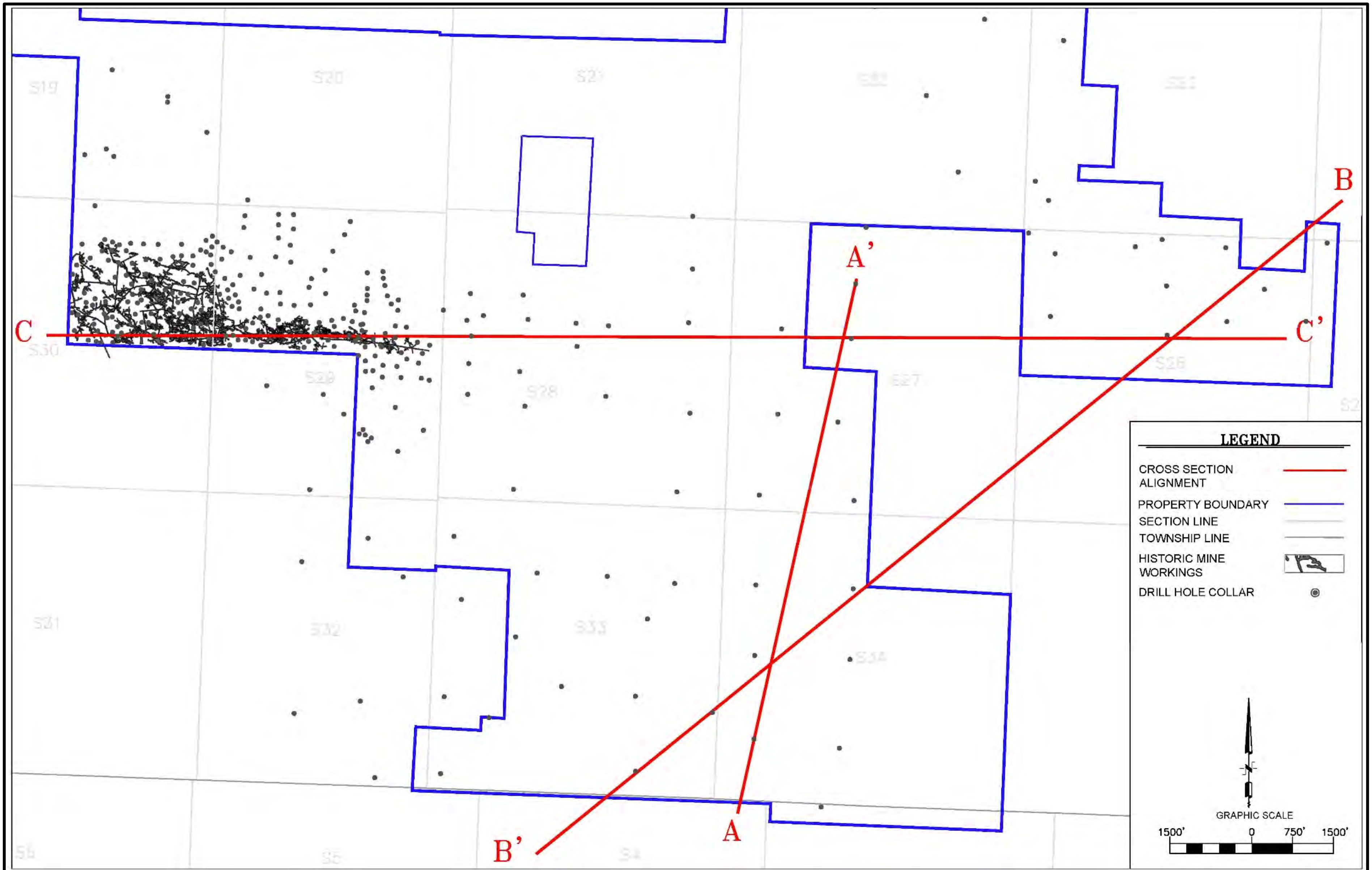
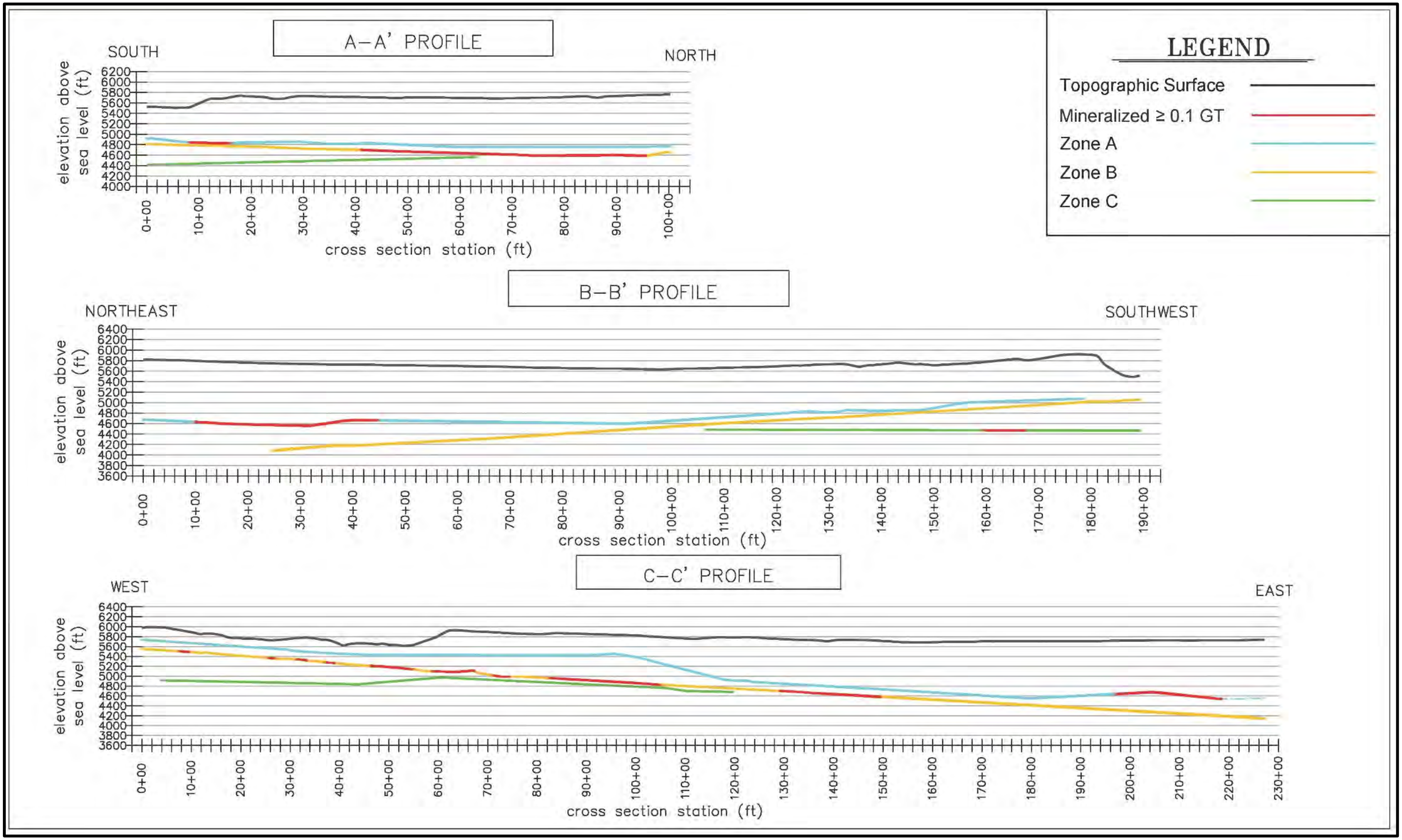


Figure 10.3 - Slick Rock Cross Sections



Section 11: Sample Preparation, Analyses, and Security

11.1 Velvet-Wood Sampling

The Velvet-Wood Mine Uranium Project was initially drilled during the 1970s and 1980s with the principal exploratory work and drilling completed by Gulf and Uranerz for the Velvet and Wood properties, respectively. As previously discussed in Section 14, the data is considered accurate and reliable for the purposes of completing a mineral resource estimate for the property.

Core drilling completed during the 2007/2008 drilling program was directly supervised by BRS and Uranium One personnel including Doug Beahm and personnel under his direct supervision. On site personnel completed lithologic logging of rotary and core samples. Upon completion of drilling, geophysical logs of the drill holes were completed by a commercial provider of such services, Century Geophysical. The loggers were contractually required to provide Uranium One with calibration data and the k-factor for their probes and completed onsite calibration for each hole.

With respect to QA/QC for equivalent uranium measurements (eU_3O_8) by downhole geophysical logging, the Department of Energy (DOE) maintains standard calibration pits located in Grand Junction, Colorado for use by the US uranium industry for instrument calibration. For Velvet and Wood, the original log files contain a record of the geophysical probes which show the instruments were calibrated at the DOE standard calibration pits located in Grand Junction, Colorado prior to the drilling program. For example, the geophysical logging unit which measured eU_3O_8 for core holes DW14T-08 and SLV-8883T-08, completed on 10/02/2008 and 9/25/2008, respectively were calibrated at the Grand Junction DOE facility on 9/22/2008.

Drill core was placed in protective plastic sleeves at the drill site and packaged into core boxes. Mineralized core was subsequently split for analysis and metallurgical testing with half of the core retained. The core splits were delivered to the testing laboratory and testing facility, Hazen Research (Hazen), by the author, Beahm, and a chain of custody established. In addition, select core samples were chosen for geotechnical testing. Chemical assays were completed by the following methods:

- Uranium by fluorometric assay.
- Vanadium, molybdenum, arsenic, iron, magnesium, aluminum, calcium, thorium, zinc, copper, nickel, cobalt, and manganese by semi-quantitative x-ray fluorescence (XRF).
- Uranium equivalent (eU_3O_8) by gamma spectroscopy.

Hazen is located at 4601 Indiana Street, Golden, Colorado, USA 80403. Hazen has provided analytical services for the uranium mining and processing industries since the early 1960s. An outgrowth of this activity has been the Radiochemistry Laboratory, which specializes in the determination of the long half-life radionuclides of the uranium and thorium decay series and radionuclides produced from nuclear power generation. These isotopes emit alpha, beta, and gamma radiation. Hazen holds a variety of state and federal certifications to perform radiochemical testing on drinking water from domestic and foreign sources, including NELAC Certification by the State of New York. Typical parameters include gross alpha/beta, gross gamma, radium-226, radium-228, radon in water, thorium, tritium, strontium, cesium, and uranium. In addition, Hazen

Analytical Laboratory holds certifications from various state regulatory agencies and from the USEPA.

It is the authors' opinion that the sample preparation, security, and analytical procedures were in keeping with industry practice and are adequate for the purposes of this report.

11.2 Slick Rock Sampling

Anfield has not conducted a drilling and/or sampling program on the Slick Rock project. The only chemical assay values are historical and were generated by the AEC laboratories. Later operators (USEC, UCNC, Homeland Uranium, Energy Fuels, and UEC) relied on radiometric values and did not perform chemical assays.

Samples were prepared by the USGS on behalf of the Raw Materials Division of the Atomic Energy Commission (AEC). USGS geologists conducted diamond drilling and radiometrically logged the holes, described the lithology, and scanned the cores for radiometric anomalies using a Geiger counter. Within Anfield's Slick Rock project area, 51 of the 52 core samples were retrieved with greater than an 80% recovery rate. Only borehole DV-88 was less than 80% at a 65% recovery rate (OFR70-348).

Sample intervals with radiometric anomalies greater than 0.045% eU_3O_8 were shipped to the AEC labs in Washington, D.C., Denver, CO, or Grand Junction, CO for chemical determination of uranium and vanadium content. The precise chain of custody of these samples is unknown. The AEC laboratories determined uranium values using fluorometric, colorimetric, volumetric, polargraphic, coulometric, radioactivation, X-ray spectrometric, and nuclear photographic plate techniques. The choice of method is determined by many factors such as the concentration of uranium in the sample, its chemical complexity, the accuracy sought, the speed required, and the availability of the instrumentation (Grimaldi, 1955). AEC laboratories determined vanadium content via wet chemical digestion and volumetric determination by using a prescribed method developed by Claude W. Sill, U.S. Bureau of Mines, Salt Lake City, Utah and compiled and edited by R. W. Langridge in AEC publication, RMO-3001. The certifications held by the AEC laboratories are unknown.

The samples were collected and processed according to strict protocols developed by the AEC and other U.S. government agencies. The results are consistent with later industry analyses. The authors believe the determinations of grade are sufficiently accurate and precise to support the estimation of mineral resources.

Section 12: Data Verification

12.1 Velvet-Wood Data Verification

The primary assay data for the Velvet-Wood Project is downhole geophysical log data. A comparison of downhole radiometric geophysical data to chemical core assays was also completed to evaluate radiometric equilibrium conditions.

Ten of the 96 Wood Project logs were chosen at random and reviewed for data entry errors. In one instance half foot uranium grade data from a printout was compared to half foot grade data that was scaled from a histogram. The two data sets varied by less than 0.002 %eU_3O_8. This amount of variance is insignificant. No grade data entry errors were found. Five drift data entry errors were corrected. Due to the preliminary amount of drift data entry errors, all drift data entries were checked and corrected if necessary. One hundred percent of the log data entry was reviewed after entry and corrected where necessary. Multiple maps were rectified, and point locations and rectifications were checked for consistency and any data entry errors.

Historic drill data for each drill hole consisting of radiometric data was posted on drill maps including collar elevation, elevation to the bottom of the mineralized intercept, thickness of mineralization, grade of mineralization, and elevation of the bottom of the hole. Data entry was checked and confirmed. Drill hole locations were digitized from the drill maps to create a coordinate listing and then plotted. The resultant drill maps were then checked and confirmed by overlaying with the original maps.

2008 drill data included collar elevation, collar location, grade and elevation of mineralized intercepts, and elevation of bottom of hole. New drill hole locations were taken from field surveys using modern survey grade GPS equipment. All historic coordinates were converted to match the Utah State Plane NAD83 coordinate system. This conversion included the re-surveying of a limited number of historic survey monuments and rectification of the historic coordinate system to the Utah State Plane NAD83 coordinate system. With this rectification, historic drill holes could be located in the field with an estimated error of approximately 15 feet. Further field surveys should be completed to increase the accuracy of historic drill hole coordinates.

A comparison was completed of historic drill hole Sum GT data with 2008 Uranium One drill hole Sum GT data for three holes completed which were intended to twin holes SLV-8806, SLV-8803, and DW-14. The closest of the 2008 core holes to historic data was SLV-8806T-08 which is approximately 23 feet to the southeast of SLV-8806 at mineralization. SLV-8806T-08 had an 8.28 GT as compared to SLV-8806 with a 6.12 GT. Drill hole SLV-8803T-08 deviated approximately 25 feet to the west from SLV-8803 at mineralization. SLV-8803T-08 had a 2.08 GT as compared to SLV-8803 which had a 9.36 GT. No deviation data is available for the historic drill hole DW-14 so the distance to the intended twin drill hole is not known at depth. The 2008 drill hole DW-14T-08 did not intercept mineralization above cutoff grade as compared to DW-14 with a 1.65 GT.

Although the GT values of holes SLV-8803T-08 and DW-14T-08 are less than the intended twin holes, the drill holes show mineralization at the same elevation, in the same host rock, and with approximately the same mineralized thicknesses. The drill holes therefore confirm the continuity of the host formation but indicate that variations in grade should be expected, as seen historically at Atlas' nearby Velvet Mine.

12.2 Slick Rock Data Verification

Anfield has not conducted any drilling activities at the Slick Rock project to verify data generated by the USGS or subsequent operators. Anfield has obtained radiometric and chemical assays and from U.S. Atomic Energy Commission's exploration program OFR70-348 for vanadium and uranium values, respectively, from those holes drilled by the USGS on behalf of the Raw Materials Division of the AEC. Logs for boreholes drilled by USEC and Energy Fuels were obtained by claim acquisition, and the uranium intercept values from the logs for boreholes drilled by Homeland Uranium were available in the public domain.

Previous owner, UEC, validated historic drill sites by locating and measuring drill hole locations in the project area using a Trimble GeoXH mapping-grade GPS unit. The authors reconfirmed multiple site locations during their site visit on April 12, 2023. The drill hole database was compared with measured geo-spatial coordinates from the previous field work where physical locations of all available drill holes were found to be consistent with their locations stated in the database.

The authors audited the OFR70-348 data from copies of the original documents and re-extracted the intercept data for comparison to the existing database acquired by Anfield in acquisition from UEC. Where data in the database was missing compared to the original Geologic and Assay Logs from the USGS that data was taken into the database. Few present inconsistencies in the UEC database were explainable by data entry error and corrected to match the original document data.

The veracity of the OFR70-348 documents was confirmed to the authors by location of multiple duplicate originals from a separate USGS file collection. The separate USGS documents were found to be identical between the USGS data set and the one provided by Anfield for 5 holes that occurred in both data sets. The 5 identical holes are: DV-5A, DV-39, DV-40, DV-41, DV-42.

A total of 312 holes are known to be contained within or proximal to the Slick Rock project area. Of that total, 27 of these holes had locations but no other data leaving 285 drill holes upon which to build a database. Of the 285 holes in the database used for resource estimation, 207 were drilled by Union Carbide, 53 by the USGS, 17 by USEC and 4 each by Energy Fuels and Homeland Uranium. Within the 285 drill holes data was available on 346 discrete intercepts distributed between 3 stratigraphically distinct zones.

Given the consistency of the results from government and private industry drilling, the ability to recover historic information in original form, the ability to locate the drill collars in the field, and the agreement of drill results with nearby mine production, the authors believe the sample data are sufficiently accurate and precise to generate an inferred mineral resource estimate as described in Section 14.

12.3 Density

12.3.1 Velvet-Wood Density

Atlas mining production reported a unit weight of 14.5 cubic feet per ton. Eight samples taken from Velvet core holes for geotechnical purposes were analyzed for density among other properties. The densities of the eight samples ranged from 123.1 to 163 pounds per cubic foot and averaged 136.1 pounds per cubic foot. This converts to an average density of 14.7 cubic feet per ton as compared to the historic value of 14.5 cubic feet per ton. In this report, for the purposes of mineral resource calculations, a density factor of 14.5 cubic feet per ton is recommended.

12.3.2 Slick Rock Density

The 1954 and 1956 USGS reports on "Accuracy of Uranium and Vanadium Estimates" assume a bulk tonnage factor in the Colorado Plateau to be 14 cubic feet per ton. The historic density expressed as a tonnage factor from Burro mine records is 15 cubic feet per ton. As the 15 cubic feet per ton is more conservative in its effect on the overall resource tonnage and pound of product and is proximal to the Slick Rock Resources, it is the most reasonable estimate of density in the opinion of the authors. Future verification drilling should incorporate a core drilling program to confirm the density factor for future resource estimation.

12.4 Downhole Deviation

Virtually all the drilling performed in both resource project areas was drilled vertically. Downhole deviation data of drill holes was primarily available for the Velvet mine portion of the Velvet-Wood project and partially available for the Wood portion. In the case of Velvet, where deviation data was available and verifiable the data was accommodated into drill hole databasing to adjust the location of the GT and T intercepts accordingly. In the cases of the Wood portion of the Velvet-Wood project and the Slick Rock project, all drilling was modeled as vertical.

12.5 Radiometric Equilibrium General Information

The dominant data available for evaluation of mineral resources of both the Velvet-Wood and Slick Rock projects was radiometric equivalent uranium data. This data consisted of radiometric geophysical logging data of each drill hole from which the uranium content was calculated using standard industry methods and calibration. Such calculations of equivalent uranium content from geophysical log data assume that the uranium is in radiometric equilibrium with its daughter products.

Radioactive isotopes decay until they reach a stable non-radioactive state. The radioactive decay products are of two general categories: the first being the sub-atomic energy generating product (i.e., alpha, beta, gamma, and neutron radiation) and the second being the atomic isotope. Decay product isotopes are referred to as daughters and occur down what is known as a decay chain. When all the decay products are maintained in close association with the primary uranium isotope U-238 for the order of a million years or more, the decay chain will reach equilibrium with the parent isotope; meaning that the daughter isotopes will be in a state of decay in the same quantity as they are being created (McKay, 2007).

An otherwise equilibrated decay system may be put into a state of disequilibrium when one or more decay products are mobilized and removed from the system because of differences in solubility between uranium and its daughter isotopes. In addition, both the primary isotope of uranium U-238 and its daughters emit different forms of radiation as they decay. The primary field instruments for the indirect measurement of uranium, either surface or down-hole probes, measure gamma radiation. Within the uranium decay chain, the gamma emitting elements are primarily Radium226, Bismuth214, and Uranium238. Of these Radium226 is the dominant source of gamma radiation.

Disequilibrium is considered positive when there is higher proportion of uranium present compared to daughters and negative where daughters are accumulated, and uranium is depleted. The disequilibrium factor (DEF) is determined by comparing radiometric equivalent uranium grade eU_3O_8 to chemical uranium grade. Radiometric equilibrium is represented by DEF of 1, positive radiometric equilibrium by a factor greater than 1, and negative radiometric equilibrium by a factor of less than 1. Negative disequilibrium occurs when uranium is separated from its daughters, specifically Radium. This occurs when the uranium mineralization is oxidized, liberating the uranium but leaving the radium in place.

Velvet-Wood project data from historical core drilling and the 2007/2008 coring program contains 41 individual core samples from 6 core holes. Comparing the core assay U_3O_8 GT values of each of the intervals to their corresponding radiometric equivalent eU_3O_8 GT values provides a DEF range of 0.81 to 1.59 with an average DEF of 1.33. Although the available data indicates a positive DEF, the authors recommend the use of a DEF factor of 1 for Velvet-Wood based of the limited number of data points and the fact that the core holes offset holes with relatively high thicknesses and grades rather than a representative sampling of the deposit.

There is very limited data available to the author from the USGS pertaining to radiometric equilibrium for the Slick Rock project. It is the author’s experience that the Colorado Plateau uranium deposits typically are neutral to slightly positive in their DEF. As such, a DEF of 1 is assumed for the Slick Rock resource estimate. Future verification drilling should incorporate core drilling samples to confirm the disequilibrium factor for future resource estimation.

Section 13: Mineral Processing and Metallurgical Testing

During the period 1953-1980, there were as many as 24 uranium and uranium/vanadium mills operating in the Colorado Plateau region of Arizona, Utah, Colorado, and New Mexico. The "gold standard" reference for the industry through 1970 was Merritt, 1971. If the vanadium content of the mill feed was sufficiently high, the mill usually had a vanadium byproduct circuit. A notable example was the Navajo mill at Shiprock, NM, built by Kerr-McGee Oil Industries Inc., later acquired by Vanadium Corporation of America and its successor, Foote Mineral Company. For operations without vanadium circuits, a vanadium penalty was sometimes assessed for toll and custom shippers.

The general processing technique employed by most mills was crushing and coarse grinding in rod mills, followed by agitated tank leaching in aqueous sulfuric acid at pH 1.5-2.0 with an oxidant like manganese dioxide or sodium chlorate, solution purification, and precipitation of a uranium oxide product. Early mills recovered uranium from the leached slurry with ion exchange resin beads suspended in mesh baskets, but commercialization of polyacrylamide flocculants allowed later plants to effect separation of the pregnant leach solution from the leached residue by counter-current decantation ("CCD") in a string of thickeners. By 1970, nearly all plants treated the clarified pregnant leach solution ("PLS") in solvent extraction ("SX") circuits using tertiary amine extractants dissolved in a diluent that was usually a high-flash point kerosene.

Some mineralized material contained sufficient calcite to render acid leaching uneconomical, and leaching was conducted at elevated temperature and pressure in agitated autoclaves with sodium carbonate and bicarbonate in an aqueous solution. In this case, carbonate ion complexed the dissolved uranium and bicarbonate ion-controlled hydroxyl ion which otherwise would have prematurely precipitated the uranium as a hydroxide. A few mills, notably Anaconda's operation at Bluewater, NM, treated ores on a toll basis and had both acid and alkaline circuits.

The plants with vanadium recovery circuits leached at a higher free acid concentration corresponding to pH 0.5-1.5 and recovered vanadium from the uranium SX waste solution ("raffinate") in another SX circuit with a different extractant, typically an aliphatic phosphoric acid, or with a different concentration in the organic phase of the same extractant.

Overall recoveries of uranium were typically in the range of 93 to 97 percent and vanadium recoveries were 70 to 80 percent, depending on mineralogy and the extent to which soluble losses could be minimized during solid/liquid separation. It is very likely that the Shootaring Canyon mill will be able to achieve at least 96 percent U_3O_8 recovery, especially given the unusually high average feed grades of 0.24 to 0.29% U_3O_8 and the high free acid concentration during leaching. The vanadium plant will have the advantage of state-of-art instrumentation and process control and may readily achieve 80% V_2O_5 recovery.

13.1 Velvet-Wood Metallurgical Studies

Metallurgical studies have been completed on mineralized material from the Velvet deposit that was recovered from core drilling completed in 2007 and 2008 at the Velvet Mine. Metallurgical testing completed to date demonstrates that the mineralized material is amenable to acid leaching with conventional mineral processing methods.

Leaching experiments for 18 Velvet core samples were completed; however, three of the extractions were low due to laboratory errors and difficulties in pH control, as discussed in the summary report (Hazen Research, Inc., 2008). The average of the 15 experiments that were conducted under near-optimum conditions was 96.1 percent uranium extraction. However, the average grade of mineralized samples used in the leaching experiments was only 0.100% U_3O_8, while the run-of-mine diluted average grade is expected to be 0.265% U_3O_8 and the average grade mined from Atlas Mineral's Velvet Mine was 0.46% U_3O_8. Therefore, the samples used in the leach experiments were substantially lower in uranium grade than the estimated grade of the Velvet and Wood mineralization. It is therefore possible that vanadium content and uranium extractions obtained in the tests were also lower than may be obtained with the estimated higher grades for mined material.

Acid consumption for baseline experiments averaged 118 lb/ton. Carbonate content in the mineralized material has a direct relationship to acid consumption during leaching and may influence uranium extractions either by causing excessive gypsum precipitation or by making pH control difficult. Sodium chlorate ($NaClO_3$) proved to be an effective oxidant. Molybdenum content for all of the core samples that were assayed averaged 99 ppm and molybdenum content in the pregnant leach solution averaged 0.17 grams per liter. Vanadium assay results from Uranium One's 2007/2008 exploration program showed an overall average of 2.13 to 1 vanadium to uranium ratio, while the historic ratio was 1.39 to 1. On average, vanadium concentrations will be less than 1.00% V_2O_5, whether based on the historic vanadium to uranium ratio, or the ratio from 2008 assays.

No metallurgical testing has been completed on the Wood property. However, given the close proximity to Velvet and the fact that the mineralization lies within the same geologic unit as Velvet, similar metallurgical test results are expected. The mineralized core recovered from Wood in 2008 had similar mineralogy to that found in mineralized core recovered from Velvet in 2007, based on geologists' direct observation of core and drill samples from both projects.

As alternatives to conventional milling, heap and vat leaching were briefly considered. However, this report is confined to agitated leaching, and there are several reasons for this decision:

- Vat leaching economics depend on rapid leaching kinetics that can be obtained in a 4- to 7-day leaching cycle, thereby minimizing the number of vats required. In order to ensure rapid solution percolation, the vat feed must be crushed to minus 0.25 to 0.5 inches, de-slimed, and the slimes separately leached in agitated tanks. Since fine particles dictate the thickener area requirement for a CCD circuit, vat leaching would require essentially the same size CCD system that conventional milling requires, negating most of the cost advantage usually attributable to vats;
- Heap leaching was applied successfully to several uranium ores during the 1960s and 1970s, but it has not been attempted when co-product vanadium is planned. Satisfactory vanadium extraction requires a higher free acid concentration, causing more severe attack of the gangue minerals and heightening the potential for secondary slimes to impair heap permeability;
- Neither vats nor heaps could reasonably be expected to achieve uranium extractions that can be obtained with milling.

Owing to the need to leach at an elevated free acid concentration to dissolve and complex vanadium, an acid consumption of 112 pounds of 98% H_2SO_4 per ton of leach feed was assumed.

The author of this section, Terry McNulty, is familiar with and has reviewed the available metallurgical testing and concludes that practices which have been employed are in keeping with industry standards, and the data available for completion of a PEA for the Project is reliable.

13.2 Slick Rock Metallurgical Studies

Anfield has not conducted any metallurgical tests for mineral processing at Slick Rock. Production from this property was processed by UCNC with acceptable recoveries by conventional milling methods for nearly 26 years. Uranium recoveries at the processing mill in Uravan, Colorado, were estimated to be 97 to 98%, and vanadium recoveries at the Rifle, Colorado, processing mill were estimated to be 85% according to personal communication with Curt Sealy, formerly with UCNC and UEC as VP-Strategic Development (Beahm, et al., 2014).

13.3 Recommended Metallurgical Recoveries

Owing to the need to leach at an elevated free acid concentration to dissolve and complex vanadium, an acid consumption of 112 pounds of 98% H_2SO_4 per ton of leach feed was assumed for the purposes of this PEA. Under these leaching conditions, the authors recommend metallurgical recoveries of at least 94% for uranium and 75% for vanadium as a conservative base case. However, it is very likely that the Shootaring Canyon Mill will be able to achieve at least 96 percent U_3O_8 recovery, especially given the high average feed grades of 0.24 to 0.29 % U_3O_8 and the high free acid concentration during leaching. The vanadium plant will have the advantage of state-of-art instrumentation and process control and may readily achieve 80% V_2O_5 recovery.

As a point of comparison, Energy Fuels, operator of the White Mesa, Utah, mill, predicted metallurgical recoveries for uranium and vanadium of 96% and 75%, respectively, from their La Sal, Utah project (Mathisen, 2022). The La Sal project is located less than 20 air miles from Velvet-Wood, is a similar sandstone-hosted uranium/vanadium deposit, and has similar uranium and vanadium grades.

Section 14: Mineral Resource Estimates

14.1 Mineral Resource Estimation

This report summarizes mineral resource for the Velvet-Wood and Slick Rock mines with mineral processing at a common facility, the Shootaring Canyon Mill. The total estimated uranium mineral resources are summarized in Table 14.1. The associated vanadium mineral resources which will be mined as a co-product are summarized in Table 14.2.

Table 14.1 - Velvet-Wood & Slick Rock Uranium Mineral Resource Summary*

Area/Classification	GT Cutoff	Pounds eU_3O_8	Tons	Avg Grade $\%eU_3O_8$
TOTAL MEASURED AND INDICATED MINERAL RESOURCE URANIUM	0.25 – 0.50	4,627,000	811,000	0.29
TOTAL INFERRED MINERAL RESOURCE URANIUM	0.25 – 0.40	8,410,000	1,836,000	0.24

*Numbers rounded

Table 14.2 - Velvet-Wood & Slick Rock Vanadium Mineral Resource Summary*

Area/Classification	GT cutoff (Based on Uranium)	V:U Ratio	Pounds V_2O_5	Tons	Avg Grade $\%V_2O_5$
TOTAL INFERRED MINERAL RESOURCE VANADIUM	0.25-0.50	4.2	54,399,000	2,647,000	1.03

*Numbers rounded

While mineral resources are not mineral reserves and do not have demonstrated economic viability, reasonable prospects for future economic extraction were applied to the mineral resource estimates herein through consideration of grade and GT cutoffs as well as mineralization proximity to existing and proposed, conceptual mining. As such, economic considerations were exercised by screening out areas which were below these cutoffs or of isolated mineralization and thus would not support the cost of conventional mining under current and reasonably foreseeable conditions.

14.1.1 Definitions

A Mineral Resource is defined as a concentration of occurrence of natural, solid, inorganic, or fossilized organic material in or on the Earth's crust in such form and quantity and of such a grade or quality that it has reasonable prospects for economic extraction. The location, quantity, grade, geological characteristics, and continuity of a mineral resource are known, estimated, or interpreted from specific geologic evidence and knowledge (CIM, 2014). Mineral resource estimates are classified as Measured, Indicated, or Inferred based on the level of understanding and definition of the mineral resource.

14.1.2 General Methodology

The GT contour method is used as common practice for Mineral Reserve and Mineral Resource estimates for similar sandstone-hosted uranium projects ("Estimation of Mineral Resources and Mineral Reserves", adopted by CIM November 23, 2003, p. 51.) It is the opinion of the author that the GT contour method, when properly constrained by geologic interpretation, provides an accurate estimation of contained pounds of uranium.

The GT contouring method is the primary method of resource estimation employed for both the Velvet-Wood and Slickrock projects in this report. The GT contour methodology was applied to all areas of mineralization outside of the Velvet Mine workings. Within the mined areas of Velvet, mineral resources were estimated based on measurements of individual blocks of remaining mineralization and assignment of average grade and thickness from face and long-hole data. Individual resource blocks for these estimates are shown on Figure 14.1.

There are minor differences in the application of the GT contouring method between the Slick Rock and the Velvet-Wood projects dictated by legacy database infrastructure and specific modelling interpretations between projects, but the overall approach to the GT contouring and the fundamental calculation of resources for each project remains the same.

For both Velvet-Wood and Slick Rock, all individual drill hole intercept data meeting or exceeding the minimum reported grades (0.05% eU_3O_8 Velvet-Wood and 0.02% eU_3O_8 for Slick Rock) were first calculated, individually multiplying the thickness in feet by a average eU_3O_8 % grade resulting in a sum GT value in feet x % eU_3O_8 for each intercept. Intercept GT values were summed within each drill hole when the intercepts represented correlated three-dimensional continuous geologic zones such as the unconformity between the Moss Back and Cutler Members at Velvet-Wood.

The summed GT intervals were composited with interstitial waste values, and in the case of Velvet-Wood then diluted to a summed minimum thickness of 4 feet to accommodate split shot ore-waste mining. If the thickness exceeded 4 feet, no dilution was added to the Velvet-Wood dataset. No minimum thickness was applied to the Slick Rock intercept data, rather the Slick Rock data was composited to the total thickness within each zone and a 0.4 GT cutoff applied to the resource estimate which constrains the resource to an average thickness of 3.8 feet, or nominally 4 feet.

Summed GT and thickness for the summed mineralized intercepts of each zone were then contoured using standard ACAD Civil-3D algorithms creating a three-dimensional surface for GT and thickness in each zone. These surfaces were then bounded based upon the geological interpretation of each deposit. Verification of the contour models was performed by inspection against all the available data prior to calculating the resource estimate. From the contoured GT ranges, the contained pounds of uranium were calculated volumetrically. The generation of these contour model volumes was done for both projects in ACAD Civil-3D but in different versions using slightly different techniques. In the case of Velvet-Wood the resource calculation was performed on a banded area times thickness basis, while Slick Rock was calculated using the Civil-3D surface volumetrics toolset. Velvet-Wood was validated using the volumetrics tool set and found to be within 1 to 3% of the banded area times thickness method. This is a reasonably small amount of variance between calculation methodologies, and cross validates the results of the same contour model calculated using both methods.

Validation of each of the sum GT and sum thickness contour models is performed via inspection of the model contours to all available data prior to resource calculation. All interpolation within the maximum radius of influence is performed via the inverse distance square method from available data when manually constructing contours. Interpolation between manual contours and points is performed by the Civil 3D standard algorithm parameters. It is the opinion of the authors that the resource models are reasonably valid within the mineral resource classification assigned to each area of each project.

14.3 Project GT Resource Modeling - Key Assumptions and Criteria

Data cutoffs and modeling assumptions are critical components of any resource modeling method. Modelling parameters are dictated by several factors including density of drilling data, deposit characteristics and interpreted geologic model. In the case of both the Velvet-Wood and Slick Rock projects, they are both stratigraphically controlled, sand-stone hosted uranium/vanadium deposits of the Colorado Plateau style, as discussed in Section 7 above. This deposit style has been modelled well in the authors experience by the GT contouring method and has yielded results which have proven accurate enough to guide mining operations for many decades.

The Modeling Assumptions and Data Cutoffs applied to each model are stated below in Table 14.3 Below:

Table 14.3 - Modeling Assumption Parameters by GT Contour Model

Modeling Assumption Parameter	GT Contour Resource Model		
	Velvet Mine	Wood Mine	Slick Rock Mine
Minimum reported grade (% eU_3O_8)	0.05	0.05	0.02
Nominal Thickness (ft)	4	4	4
Maximum Radius of Influence (ft)	100	100	400
Radiometric Equilibrium Factor (DEF)	1	1	1
Bulk Tonnage Factor (cft/st)	14.5	14.5	15
Minimum Sum GT Resource Model Cutoff	0.25 - 0.50*	0.25	0.40

Minimum grade and thickness criteria are used to define mineralized intercepts for resource modeling purposes. These are applied to each individual mineralized intercept and then to the sum GT of intercept composites are applied to the data prior to contour modeling. Data not meeting these minimum requirements are removed from the modeling data set and have no influence on the contour model other than establishing its boundaries.

As discussed previously, a minimum thickness dictated by mining approach is typically applied at the data preparation level and thus some mining dilution can be accounted for as was done for Velvet-Wood at the minimum mining thickness of 4 feet. In the case of Slick Rock, the average thickness was 3.8 feet, or essentially equal to the minimum mining thickness, so the minimum thickness was not applied.

Maximum radius of influence is influenced by the drilling density and the continuity of the deposit model. The tighter drilling spacing of the Velvet and Wood data allows for a smaller maximum radius of influence and a more certain resource classification. The larger drill spacing available at Slick Rock provides decreased certainty and a lower resource classification in the Inferred category.

The bulk tonnage factors and DEF discussed in Section 12 of this report were used in the calculation of the resource quantities from the sum GT and sum thickness contour model volumes.

The minimum sum GT contour resource model cutoff is the primary cutoff criteria applied to the contour model volume as the initial screening of those portions of the model quantities not meeting the criteria for reasonable economic extraction. In addition, individual model areas outside the conceptual mine limits not meeting a minimum of 10,000 lbs of eU_3O_8 resource were dropped from the resource totals as not meeting a minimum expectation of reasonable economic extraction.

14.4 Reasonable Prospects for Economic Extraction and Cutoff Criteria

Based on conceptual mine limits as discussed in Section 16 and the average grade, thickness and GT criterion applied to the estimate, it is the authors' opinion that the mineral resources estimated for the project which include the Velvet-Wood and Slick Rock mines can be reasonably and economically recoverable through underground mining methods including haulage from the mine sites to the Shootaring Canyon Mill for conventional mineral processing and product recovery. Both mines need to operate simultaneously in order to meet the mill tonnage capacity and/or an alternate feed would be needed.

The project economics as defined in the PEA and presented in Section 21 and 22 has a positive NPV and a reasonable internal rate of return based on commodity prices of $70 per pound for uranium oxide and $12 per pound for vanadium pentoxide as discussed in Section 19.

As previously discussed, a minimum mining thickness of 4 feet was applied to the Velvet-Wood and Slick Rock mines. The minimum GT applied to the mineral resource estimate varied from 0.25 to 0.50 at Velvet-Wood and was 0.40 at Slick Rock. The minimum GT cutoff criteria defines the lowest volume and quality (thickness and grade) of mineralized material which would break even with respect to marginal operating costs. In practice, the mine would operate at a higher or primary cutoff until the capital for the mine and mill was recovered. Where it is necessary to excavate mineralized material below this primary cutoff and above the minimum cutoff, this material would be stockpiled and the cost of excavation and handling this material born by the primary mined material. Thus, this marginal mineralized material could later be recovered if it meets haulage and milling costs. Note if the marginal mineralized material were treated as mine waste, the same general cost excavate and handle this would be incurred with no possible future benefit.

The lowest cutoff criteria was therefore a 4 foot minimum thickness at a 0.25 %ft GT, equating to an average grade of 0.065 $\%eU_3O_8$. The lowest Vanadium to Uranium (V:U) ratio is at Velvet and is 1.4:1 resulting in an average grade of 0.091 $\%V_2O_5$.

- At 0.065 $\%eU_3O_8$ contained pounds equal 1.3 lbs U_3O_8 per ton
- At 92% recovery this equals 1.2 lbs U_3O_8 recovered per ton

- At \$70/lb sales price, the gross value of one ton of material at 0.065 %eU_3O_8 is approximately \$84 per ton.
- At 0.09 %V_2O_5 contained pounds equates to 1.8 lbs %V_2O_5 per ton
- At 75% recovery this equates to 1.4 lbs V_2O_5 recovered per ton
- At \$12/lb sales price, the gross value of one ton of material at 0.09 %V_2O_5 is approximately \$17 per ton
- Overall, the value per ton at the minimum cutoff and at the lowest V:U ratio is thus \$101/ton.
- The PEA estimates a haulage cost of \$21/ton and a milling cost of \$70/ton or a total of \$91/ton.
- Assuming the mining costs are written off against the primary mined material, the minimum cutoff criteria would thus represent a breakeven cost.

The author concludes that application of both the minimum grade and minimum GT cutoffs represent a breakeven point with respect to mineral value and cost of production.

For this PEA, the mine limits and cutoff criteria, including the conceptual mine limits, were applied to the mineral resource estimate to segregate mineral resources having reasonable prospects for eventual economic extraction from within the overall envelope of mineralization. This resulted in a reduction of the estimated mineral resource as shown on Figures 14.1 through 14.6 at an average grade approximately five times the minimum cutoff grade. It is recommended that mine plans and costs be updated in a future preliminary economic assessment or pre-feasibility study.

14.5 Measured Mineral Resources, New Velvet Mine

Measured mineral resources are limited to the New Velvet area in Section 2, Township 31 South, Range 25 East (Figure 14.3). The current estimate follows with the recommended cutoff, 0.25 GT, highlighted:

Table 14.4 – New Velvet Measured Mineral Resources*

GT minimum	Pounds eU3O8	Tons	Average Grade %eU_3O_8	Average Thickness (feet)
0.25	1,966,000	362,600	0.27	6.7
0.50	1,836,000	282,700	0.32	6.9
1.00	1,571,000	187,000	0.42	7.1

*Numbers rounded

14.6 Indicated Mineral Resources, Old Velvet Mine

The Old Velvet Mine Area is located in Section 3, Township 31 South, Range 25 East as shown on Figure 14.1. The mineral resource estimate addresses an undeveloped area (Area III) of the Old Velvet Mine and Areas I, II, IV, and East Side of the mine that were developed but left unmined. Areas I, II, IV, and East Side were closely delineated with underground face and longhole sampling as reported by Price, 1987. Area III was delineated by surface drill holes on approximate 100-foot centers.

Old Velvet Mine Area III - Resource Calculation Methods

Resource calculations were completed using the GT Contour method previously discussed. Although a mineral resource classification as Measured may be appropriate as discussed above for the New Velvet Mineral resources in Section 2, a classification of Indicated Mineral Resources is recommended for Old Velvet Mine Area III as the data has yet to be verified by surface drilling and is currently inaccessible for underground sampling. The current mineral resource estimate for Old Velvet Mine Area III follows:

Table 14.5 – Old Velvet Mine Area III Indicated Mineral Resources*

GT minimum	Pounds eU_3O_8	Tons	Average Grade $\%eU_3O_8$	Average Thickness (feet)
Undiluted				
0.50	39,000	5,100	0.38	2.2
Diluted**				
0.50	39,000	9,200	0.21	4.0

*Numbers rounded **used in summary Table 14.7 not additive to total

Old Velvet Mine Areas I, II, IV, and East Side - Resource Calculation Methods

The following are the current estimates of mineral resources for Old Velvet Mine Areas I, II, IV, and East Side (refer to Figure 14.1). These unmined areas were designated as Areas I, II, IV, and East Side and were sampled underground using a combination of face and longhole drill samples. The data was posted on underground mine maps (Price, 1987) which were used as the basis for Figure 14.1. The authors have audited the Price, 1987 data and have used the data as the basis of the current resource estimate. In the course of this estimate the following checks and calculations were made:

- The data was reviewed to assure that the posted data matched the data utilized in the calculations.
- The area of influence assigned to the data was reviewed and confirmed, specifically;
    - Rib and face samples were projected 10 feet into the rib face or through the pillar if other sides of the pillar were accessible and the projection was justified by the data.
    - Long-hole samples were projected 10 feet on each side of the long-hole fans.
- Density was reviewed. A density of 13 cubic feet per ton was used as compared to the 14.5 cubic feet per ton recommended in this report. This would have the effect of overstating the tonnage by 10% if the 14.5 cubic feet per ton were correct. However, the GT cutoff employed in the estimate was 0.6 as compared to the 0.5 to 0.25 range recommended in this report, which would offset this difference.
- Average thickness and grade were compared to all other sources of data including surface drill data.

- Mineralized areas delineated on the mine maps were digitized into AutoCAD and the total area, tonnage, and pounds were calculated and compared to the 1987 Price estimate.

The current mineral resource estimate using the methodologies described above for the Old Velvet Mine Areas I, II, IV, and East Side follows:

Table 14.6 - Old Velvet Areas I, II, IV, and East Side Indicated Mineral Resources*

GT minimum	Pounds eU_3O_8	Tons	Average Grade $\%eU_3O_8$	Average Thickness (feet)
Undiluted**				
0.50	509,000	62,000	0.41	5.02

*Numbers rounded   **used in summary, Table 14.7 not additive to total

Although a mineral resource classification of Measured for Old Velvet Areas I, II, IV, and East Side by CIM definitions may be appropriate based on the level of detail reflected in the data and the estimation, a classification of Indicated Mineral Resources is recommended for Old Velvet Areas I, II, IV, and East Side as the data has yet to be verified by field data. The area is currently inaccessible as the mine is flooded, and verification drilling from the surface would be impractical as surface drilling would likely not be able to maintain circulation in the vicinity of the mine openings.

Table 14.7 - Total Indicated Mineral Resources Old Velvet Mine Area**

GT minimum	Pounds eU_3O_8	Tons	Average Grade $\%eU_3O_8$
0.50	548,000	71,200	0.38

*Numbers rounded   ** Sum of Areas I, II, III, and IV

14.7 Indicated Mineral Resources, Wood Mine

The current indicated mineral resource estimate for the Wood project area, utilizing the GT contour method is shown on Figure 14.2, Wood Project Resource GT Map. A GT cutoff of 0.25 is recommended for reporting purposes in this report and is highlighted in the following table.

Table 14.8 - Total Indicated Mineral Resources Wood Mine

GT minimum	Pounds eU_3O_8	Tons	Average Grade $\%eU_3O_8$
0.25	2,113,000	377,000	0.28
0.50	1,940,000	275,200	0.35
1.00	1,581,000	155,500	0.51

*Numbers rounded

14.8 Inferred Mineral Resources, Velvet-Wood

Inferred mineral resources were estimated for limited areas in both the Velvet and Wood areas where a reasonable prospect of mineralization could be based on geologic data from drilling but where drill spacing exceeded 100 feet. The areas where inferred mineral resources are projected for the Velvet and Wood Areas are shown on Figures 14.3 and 14.2, respectively.

Table 14.9 - Total Inferred Mineral Resources Velvet-Wood Areas

Resource Area	GT Cutoff	Pounds eU_3O_8	Tons	Average Grade $\%eU_3O_8$
Wood	0.25	34,500	11,000	0.16
Velvet	0.25	517,500	76,000	0.34
TOTAL		552,000	87,000	0.32

*Numbers rounded

14.9 Inferred Mineral Resources, Slick Rock

Inferred mineral resources for the Slick Rock area were evaluated based on reasonable prospects for future economic extraction through consideration of grade and GT cutoffs as well as mineralization proximity to existing and proposed conceptual mining. As such economic considerations were exercised by screening out areas of which were below these cutoffs or of isolated mineralization and thus would not support the cost of conventional mining under current and reasonably foreseeable conditions. All areas of resource falling below the screening criteria for reasonable economic prospects are shown in Figures 14.4, 14.5 and 14.6 as gray hatching and labeled.

A sensitivity analysis was performed on the mineral resource models for each zone as shown on Table 14.10. The authors recommend the 0.40 GT cutoff for the Slick Rock mine. With further definition of the mineral resource via drilling and additional mine design and cost evaluation, it is the authors' opinion that the minimum GT cutoff may be lowered.

Table 14.10 - Slick Rock Inferred Resource Sensitivity Analysis

Mineral Resource Estimates (0.02% Grade Cutoff)	Tons (millions)	Average Sum Thickness (ft)	Average Grade (%eU_3O_8)	Pounds eU_3O_8 (millions)
Zone A (Upper)				
0.10 GT cutoff	1.3	3.6	0.17	4.1
0.25 GT cutoff	0.8	4.0	0.22	3.7
0.40 GT cutoff	0.7	4.1	0.26	3.4
Zone B (Middle)				
0.10 GT cutoff	3.2	3.4	0.11	7.0
0.25 GT cutoff	2.2	4.4	0.13	5.6
0.40 GT cutoff	1.0	3.6	0.21	4.3
Zone C (Lower)				
0.10 GT cutoff	0.1	2.4	0.10	0.3
0.25 GT cutoff	0.1	5.3	0.10	0.2
0.40 GT cutoff	0.1	5.7	0.11	0.1
ALL ZONES GRAND TOTALS				
0.10 GT cutoff	4.6	3.4	0.13	11.4
0.25 GT cutoff	3.1	4.3	.15	9.5
0.40 GT cutoff	1.8	3.8	.23	7.9
Note: 1. Mineral Resources are not mineral reserves and do not have demonstrated economic viability. 2. Numbers are rounded				

Table 14.11 summarizes the inferred mineral resources at the recommended GT cutoff.

Table 14.11 - Total Inferred Mineral Resources Slick Rock Area

Resource Zone	GT Cutoff	Pounds eU_3O_8	Tons	Average Grade %eU_3O_8
Zone A (Upper)	0.40	3,403,000	659,000	0.26
Zone B (Middle)	0.40	4,316,000	1,026,000	0.21
Zone C (Lower)	0.40	139,000	64,000	0.11
TOTAL		7,858,000	1,749,000	0.23

14.10 Uranium Mineral Resource Summary

Mineral resources for the Velvet-Wood and Slick Rock Uranium Projects are summarized in the following table and include the sum of measured and indicated mineral resources and the inferred mineral resources.

Table 14.12 - Velvet-Wood & Slick Rock Uranium Mineral Resource Summary*

Area/Classification	GT cutoff	Pounds eU_3O_8	Tons	Average Grade $\%eU_3O_8$
Velvet Measured Mineral Resource	0.25	1,966,000	362,600	0.27
Velvet Indicated Mineral Resource	0.50	548,000	71,200	0.38
Wood Indicated Mineral Resource	0.25	2,113,000	377,000	0.28
TOTAL MEASURED AND INDICATED MINERAL RESOURCE		4,627,000	810,800	0.29
Velvet Inferred	0.25	517,500	76,000	0.34
Wood Inferred	0.25	34,500	11,000	0.16
Slick Rock Zone A Inferred	0.40	3,403,000	659,000	0.26
Slick Rock Zone B Inferred	0.40	4,316,000	1,026,000	0.21
Slick Rock Zone C Inferred	0.40	139,000	64,000	0.11
TOTAL INFERRED MINERAL RESOURCE		8,410,000	1,836,000	0.24

*Numbers rounded

Mineral resources are not mineral reserves and do not have demonstrated economic viability in accordance with CIM standards. At a minimum, a Preliminary Feasibility Study (PFS) is required to demonstrate the economic viability of the measured and indicated mineral resources and qualify an initial estimate of mineral reserves. This report is a restricted disclosure as allowed under section 2.3(3) of NI 43-101 which includes a Preliminary Economic Assessment (PEA) and is preliminary in nature such that it includes a portion of the inferred mineral resources as reported in Section 14 of the report. Inferred mineral resources are too speculative geologically to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the outcomes estimated in the PEA will be realized.

While mineral resources are not mineral reserves and do not have demonstrated economic viability, reasonable prospects for future economic extraction were applied to the mineral resource estimates herein through consideration of grade and GT cutoffs as well as mineralization proximity to existing and proposed conceptual mining. As such, economic considerations were exercised by screening out areas of which were below these cutoffs or of isolated mineralization and thus would not support the cost of conventional mining under current and reasonably foreseeable conditions. All areas of resource falling below the screening criteria for reasonable economic prospects are shown in Figures 14.1, 14.2, 14.3, 14.4, 14.5, and 14.6 as gray hatching.

14.11 Vanadium Mineral Resource Summary

Within the Colorado Plateau and specifically within the Uravan Belt, uranium and vanadium occur together. From the 1930s through 1945 the majority of the historic mining recovered only vanadium. Beginning in the late 1940s the emphasis shifted to uranium mining and most of the mines in the district recovered uranium and vanadium as co-products. This is true of the Velvet-Wood and Slick Rock mines. Both the Velvet-Wood and Slick Rock mines have past production of both uranium and vanadium.

The Velvet mine was mined by Atlas Minerals who mined portions of the deposit producing approximately 400,000 tons of material at grades of 0.46 %U_3O_8 and 0.64 %V_2O_5 (approximately 4 million lbs uranium and 5 million lbs vanadium) during the period 1979-1984 (Chenoweth, 1990). Vanadium assay results from Uranium One's 2007/2008 exploration showed an overall average of 2.13 to 1 vanadium to uranium ratio, while the historic ratio was 1.39 to 1. The authors recommend using a vanadium to uranium ratio of 1.4:1 for estimating the Velvet-Wood vanadium mineral resource.

The Slick Rock Project is located within the Uravan Mineral Belt which was defined as early as 1952 by the USGS as an elongated area in southwestern Colorado wherein uranium-vanadium deposits in the Salt Wash Member of the Morrison Formation are concentrated (Chenoweth, 1981). The district was first mined for radium and later vanadium. Early geologic reports (Garrels and Larsen, 1959) refer to the mineral deposits in the Salt Wash Member of the Morrison Formation as "vanadium-uranium deposits with the V:U ratio between 5:1 and 10:1 in the Uravan mineral belt of western Colorado." Chenoweth further states that the Uravan area produced 14,675,000 tons with average grades of 1.24% V_2O_5 and 0.24% U_3O_8, or a V:U ratio of 5.2:1 (Chenoweth, 1981). Production from the Slick Rock District is reported as approximately 9,000 tons of U_3O_8 and 50,000 tons of V_2O_5 or a V:U ratio of 6:1. The authors recommend use of a V:U ratio of 6:1 for estimating the Slick Rock vanadium mineral resource.

It is the authors' opinion that relying on the V:U ratio demonstrated by mine production at the Burro mine which is within the Slick Rock Project to estimate vanadium grade based on uranium grades is reasonable, especially in the category of Inferred Mineral Resource which is defined as:

An "Inferred Mineral Resource" is that part of a Mineral Resource for which quantity and grade or quality can be estimated on the basis of geologic evidence and limited sampling and reasonably assumed, but not verified, geological and grade continuity. The estimate is based on limited information and sampling gathered through appropriate techniques from location such as outcrops, trenches, pits, workings, and drill holes. (CIM, 2005)

Table 14.10 summarizes the Inferred Mineral Resource for uranium and vanadium at various cut-off grades, based on the mineral resource estimates herein for uranium and the application of V:U ratios of 1.4:1 and 6:1 for the Velvet-Wood and Slick Rock projects.

Table 14.13 - Velvet-Wood & Slick Rock Vanadium Mineral Resource Summary*

Area/Classification	GT cutoff (Based on Uranium)	V:U Ratio	Pounds V_2O_5	Tons V_2O_5	Avg Grade $\%V_2O_5$
Velvet Inferred Mineral Resource	0.25	1.4	2,752,400	362,600	0.38
Velvet Inferred Mineral Resource	0.50	1.4	767,200	71,200	0.53
Wood Inferred Mineral Resource	0.25	1.4	2,958,200	377,000	0.39
Velvet Inferred	0.25	1.4	724,500	76,000	0.48
Wood Inferred	0.25	1.4	48,300	11,000	0.22
Slick Rock Zone A Inferred	0.40	6	20,418,000	659,000	1.56
Slick Rock Zone B Inferred	0.40	6	25,896,000	1,026,000	1.26
Slick Rock Zone C Inferred	0.40	6	834,000	64,000	0.66
TOTAL INFERRED MINERAL RESOURCE	0.25-0.50	4.2	54,398,600	2,646,800	1.03

*Numbers rounded

Figure 14.1 - Old Velvet Mine GT and Resource Map

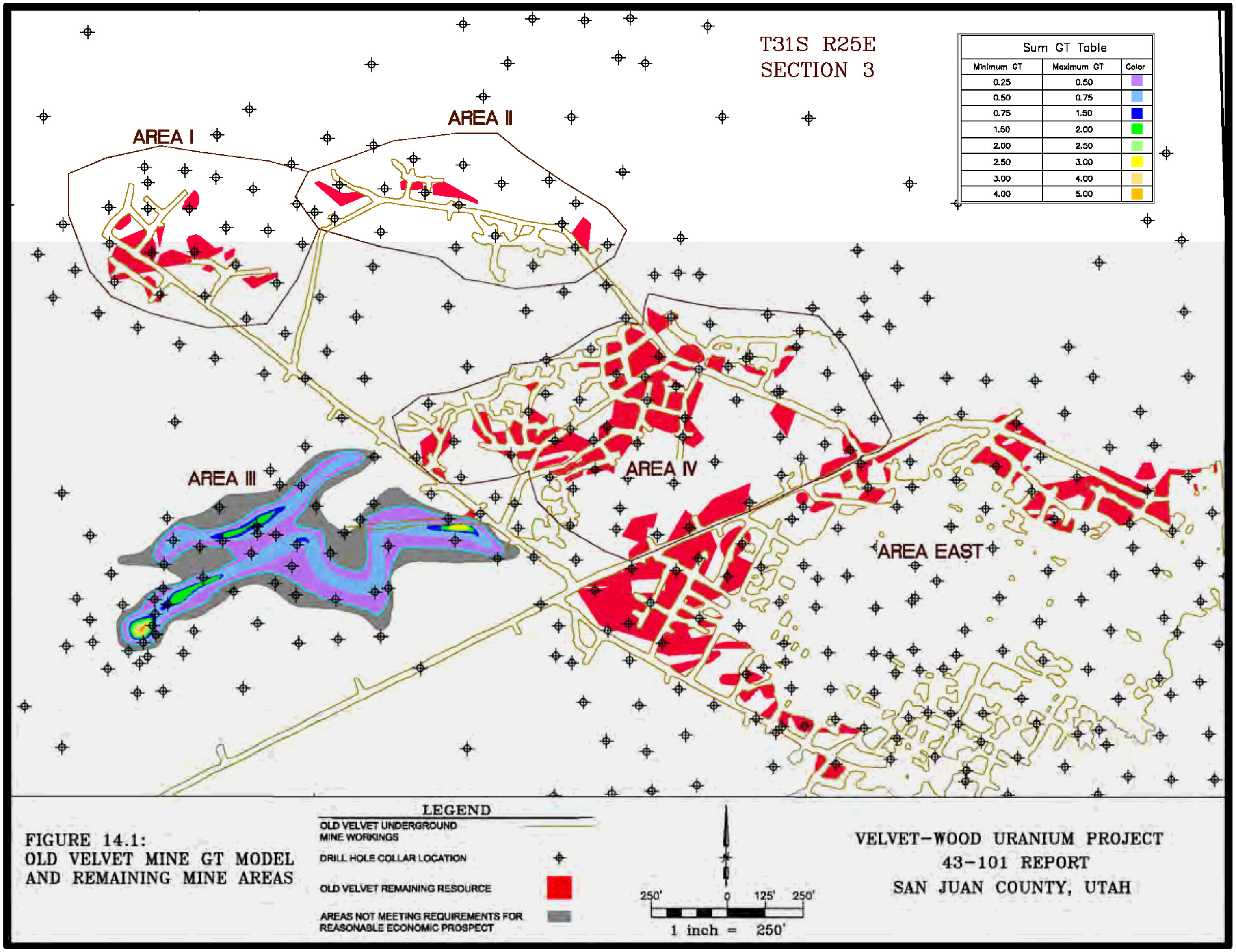


Figure 14.2 - Wood Resource GT Map

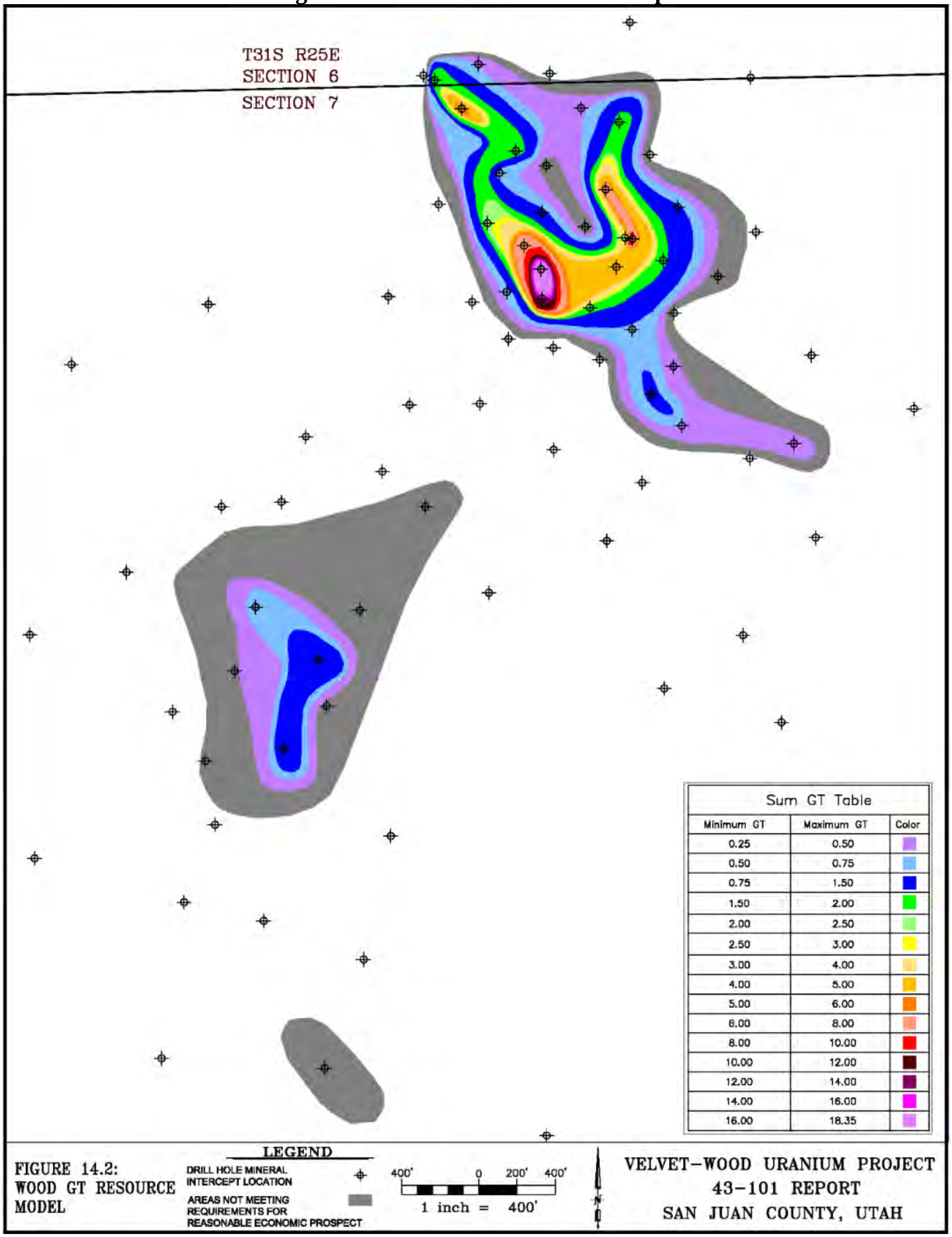


Figure 14.3 – New Velvet GT Map

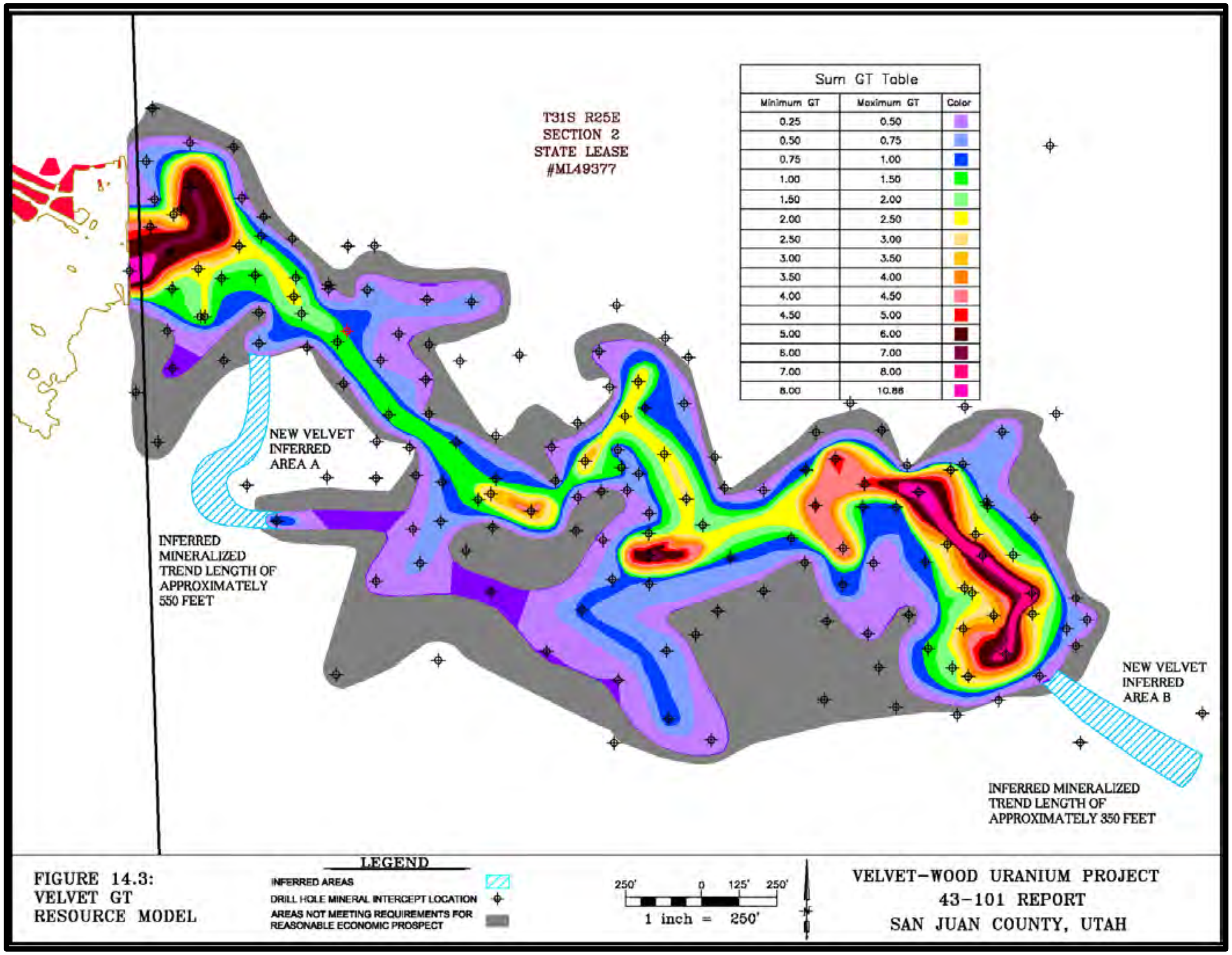


Figure 14.4 - Slick Rock Zone A GT Map

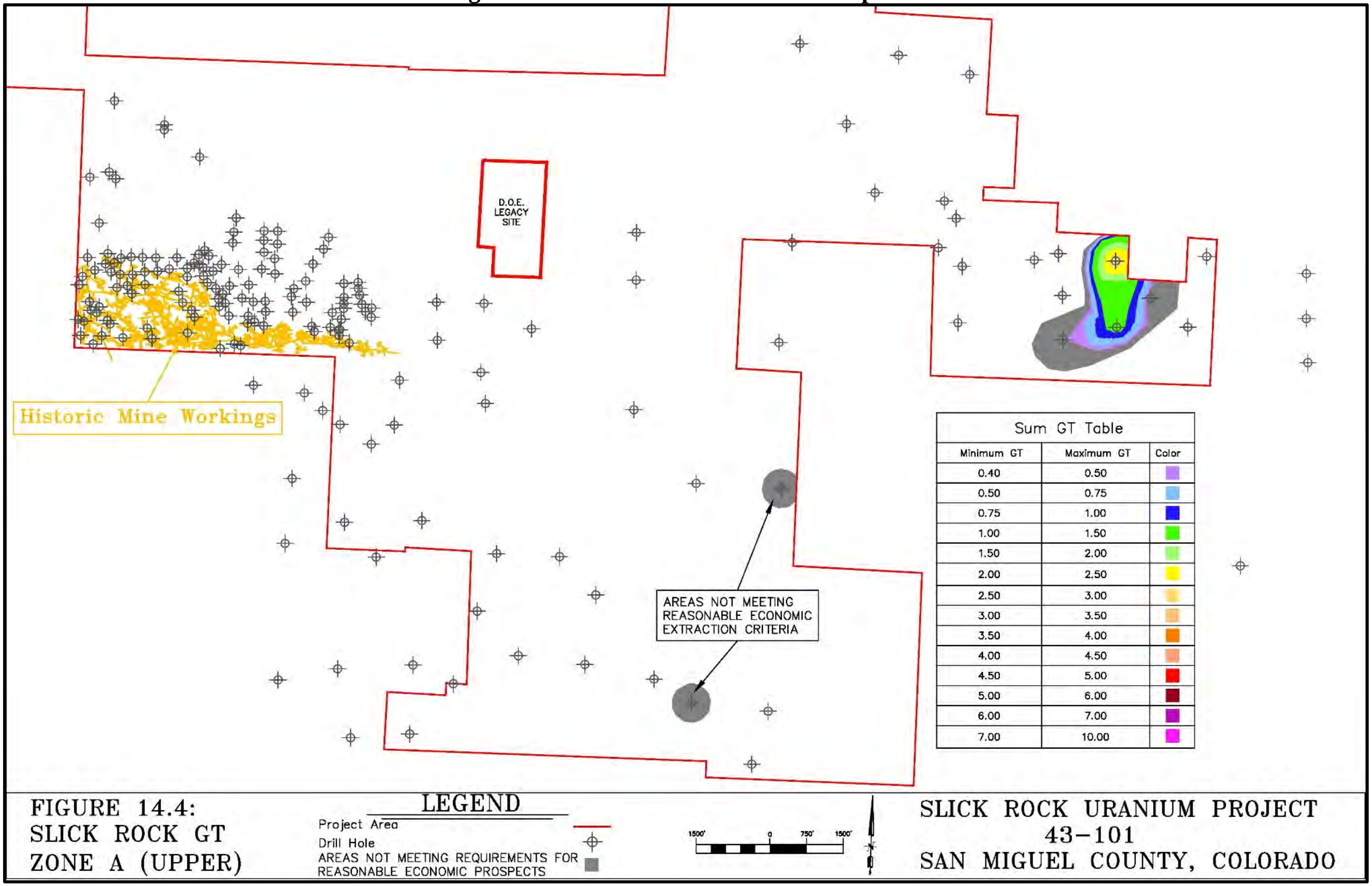


Figure 14.5 - Slick Rock Zone B GT Map

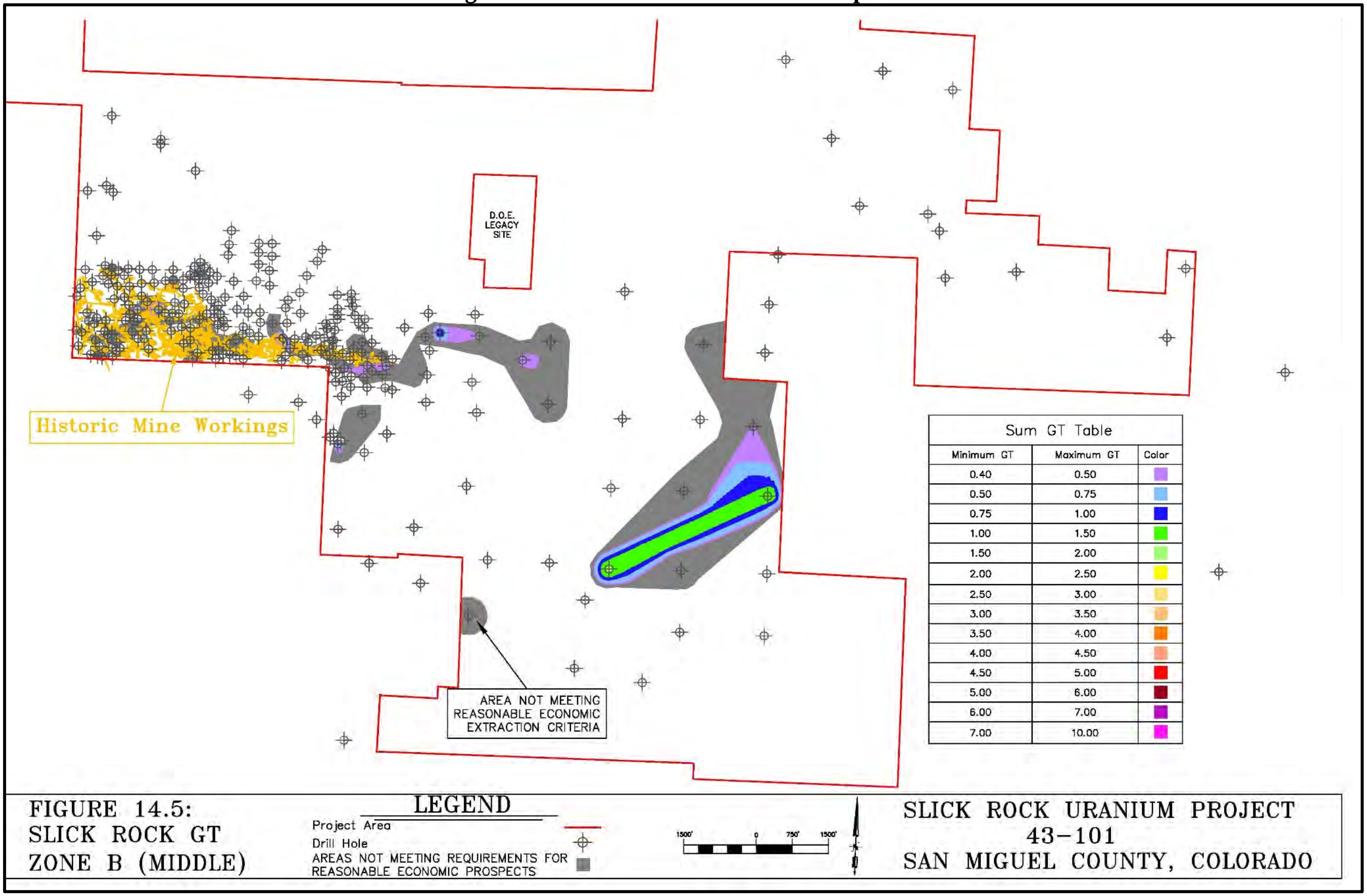
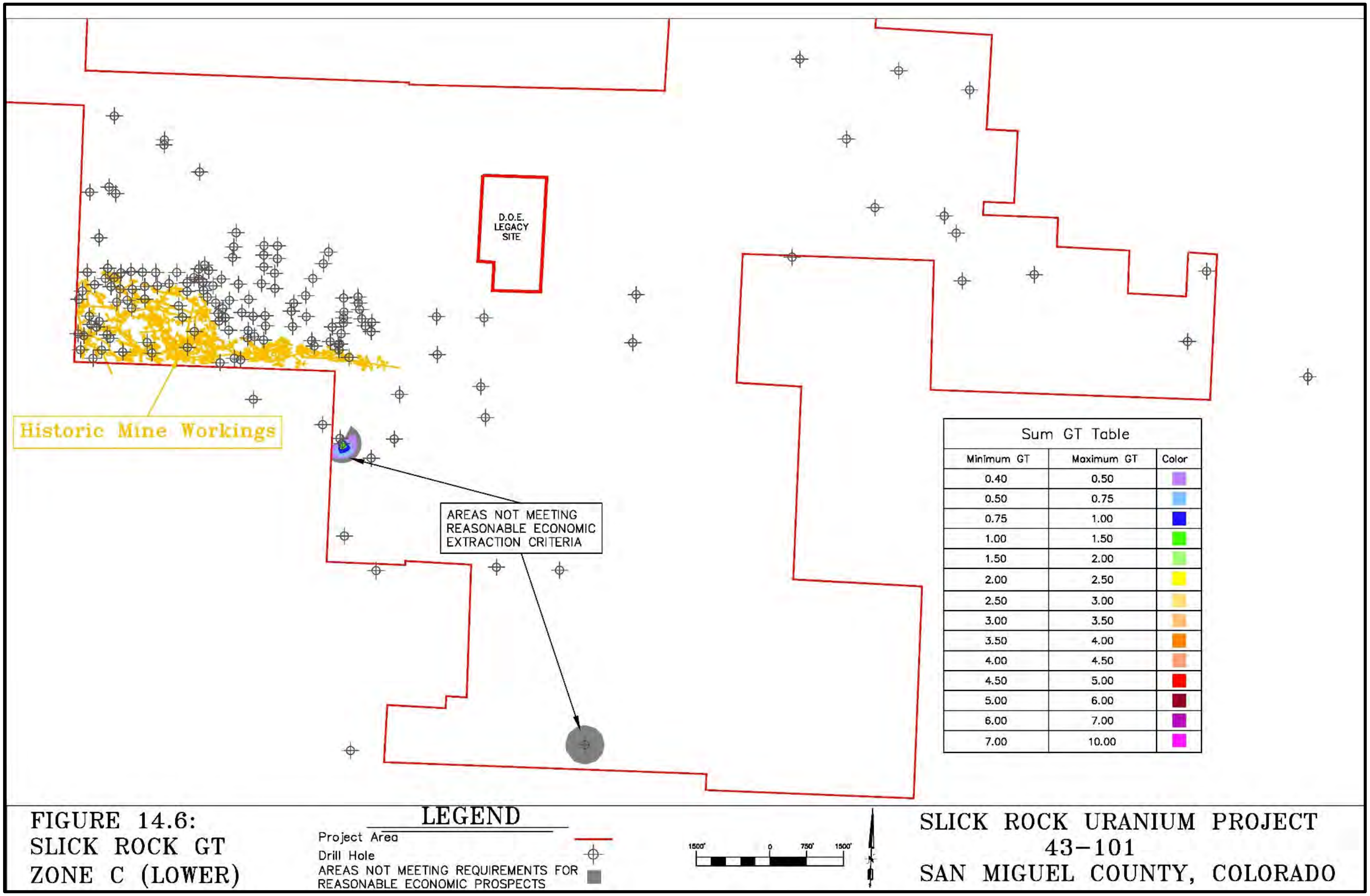


Figure 14.6 - Slick Rock Zone C GT Map



Section 15: Mineral Reserve Estimates

Not Applicable.

Section 16: Mining Methods

16.1 Mining Basis

The PEA is based on a random room and pillar mining method as was previously employed for underground uranium mining throughout the Colorado Plateau. The historic Velvet Mine, the old Wood Mine to the northwest of the Wood resource, and the Burro Mines directly west of the Slick Rock resource were all historically operated using a random room and pillar and retreat mining method. The room and pillar mining method is thus a proven method in both districts and is considered to be the best choice by the authors for the Velvet-Wood and Slick Rock projects. The characteristics of the Velvet-Wood and Slick Rock mineral deposits are compatible with this method in that their mineralization is generally tabular with some moderate rolls, low to moderate dip, and good rock strength with respect to both roof and floor. The randomness of the room and pillar extraction is due to the variations in uranium grade and thicknesses encountered. Typically, mining will follow the mineralization through underground long-hole drilling in advance of mining, face sampling, and geologic mapping concurrent with mining. Pillars are left where the mineralization is weaker in terms of concentration and/or thickness; however, in some cases temporary roof support will be necessary. The nature of mineralization lends itself to a high extraction rate but requires selective mining.

The conceptual mine layouts for Velvet and Wood are shown on Figures 16.1 and 16.2 and the conceptual mine layouts for Slick Rock are shown on Figure 16.3. The portions of the mineral resources included within the conceptual mine design and used in the PEA are summarized on Table 16.1 which follows.

Table 16.1 - Mineral Resources Included in PEA

	Portion of Mineral Resource include in PEA			
	Velvet (M&I)	Wood (Indicated)	Slick Rock (Inferred)	Mill Stockpile
Tons	429,313	251,358	1,685,000	77,514
Pounds eU_3O_8	2,714,432	1,923,187	7,719,000	250,188
Grade $\%eU_3O_8$	0.316	0.383	0.229	0.161
Percent Extraction	89.54%	89.55%	90.00%	100%

Mineral resources not included in the PEA include Velvet-Wood inferred mineral resources (Table 14.7), Slick Rock Zone C inferred mineral resource (Table 14.9), and the Patty Ann stockpile (Table 16.2). While these areas were not included in the PEA, they do have reasonable prospects for eventual economic extraction especially after CAPEX has been recovered. Reasonable prospects for future economic extraction were applied to the mineral resource estimate herein through consideration of grade and GT cutoffs and by screening out areas of isolated mineralization which would not support the cost of conventional mining under current and reasonably foreseeable conditions.

In addition, Anfield controls mineralized stockpiles at two locations: a single stockpile at the Patty Ann mine area near the Velvet Mine, and several stockpiles at the Shootaring Mill. In March 2015, BRS completed measurement of the stockpile volumes via ground volumetric surveys using a sub centimeter Trimble GPS system and sampling to determine the average uranium grades of the stockpiles.

Stockpiles were sampled at the same time volumetric surveys were completed in March 2015 by BRS. Prior to sampling, surface gamma surveys were completed, and the sampling sites selected to represent approximate average conditions. While the samples are considered to be representative, actual concentrations may vary. A description of the stockpile sampling follows.

- The mill stockpiles are located within a licensed mill site. Sampling was conducted by Uranium One personnel at the locations selected by BRS using a small backhoe. The mill stockpiles consist of 4 smaller separate stockpiles (No. 1 through 4) and one large stockpile (No. 5). A single sample was taken from each of the smaller stockpiles which were analyzed separately. Samples from the larger stockpile were taken at 5 separate locating and composited into a single sample for analysis. Approximately 20 kg of sample was taken from Stockpile No. 5 along with approximately 5 kg from each of the stockpiles No. 1 through 4. Uranium One personnel shipped the mill stockpile samples to the laboratory directly along with along with proper chain of custody forms.
- The Patty Ann stockpiles are located near La Sal, Utah near the junction of the Big Indian and Lisbon Valley roads less than 20 miles from the Velvet mine. The Patty Ann stockpile samples were taken from five separate locations across the pile using a hand auger. Approximately equal volumes were taken from each location then combined into a single composite sample which was split using a rifling splitter prior to submission to the laboratory. BRS delivered the Patty Ann stockpile to the laboratory along with proper chain of custody forms.

Analysis of the samples was completed by Inter-Mountain Labs (IML) of Sheridan Wyoming. IML is a duly licensed and certified laboratory. Samples were analyzed of both uranium and vanadium content using standard ICP methods. (Refer to Beahm, et al, 2016). The results of the stockpile volumetric estimation and sampling are summarized on Table 16.2.

Table 16.2 - Velvet-Wood Existing Stockpiles

	Uranium		
Location	**Tons**	**%U_3O_8**	**Lbs**
Shootaring Mill			
Stockpile 1	965	0.238	4,594
Stockpile 2	6,734	0.211	28,418
Stockpile 3	2,680	0.081	4,341
Stockpile 4	2,320	0.061	2,835
Stockpile 5	64,815	0.162	209,999
Total Shootaring Mill*	77,514	0.161	250,188
Patty Ann Stockpile**	48,576	0.123	119,496
Total Stockpiles	126,090	0.147	369,684

Figure 16.1 - Velvet-Wood Mine Surface Facilities Plan

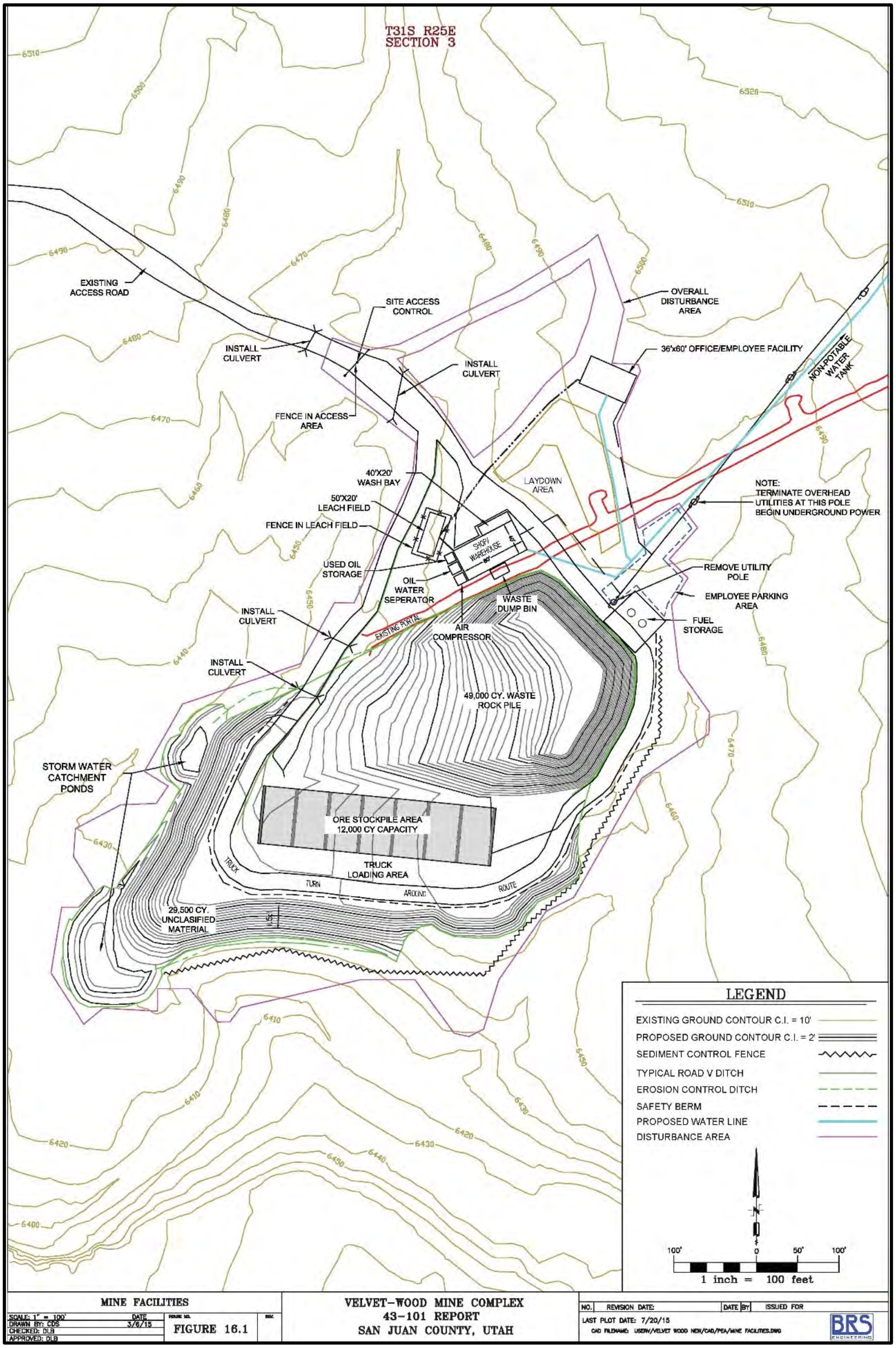


Figure 16.2 - Isometric of Wood and Velvet Underground Mine Plan

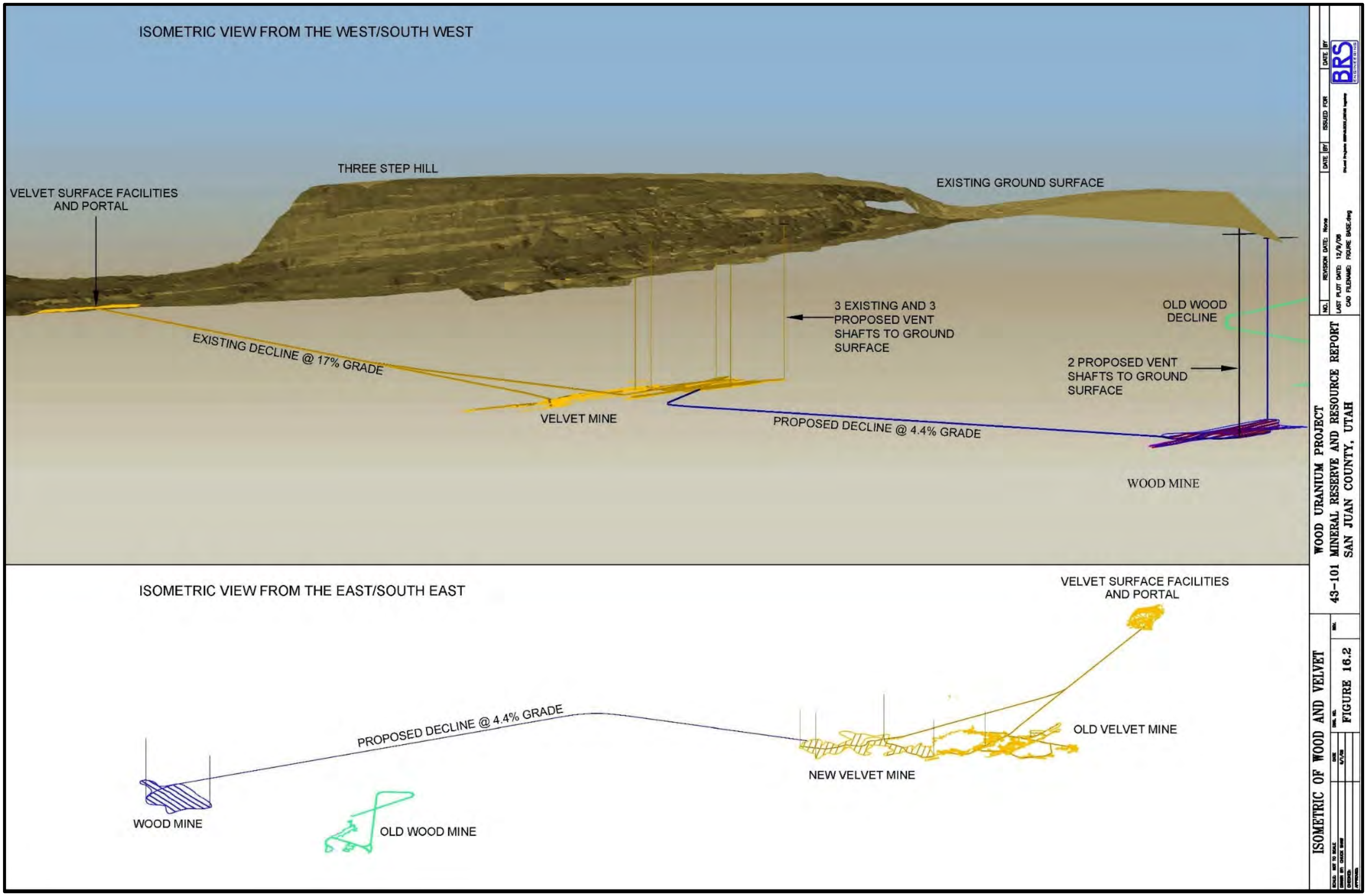
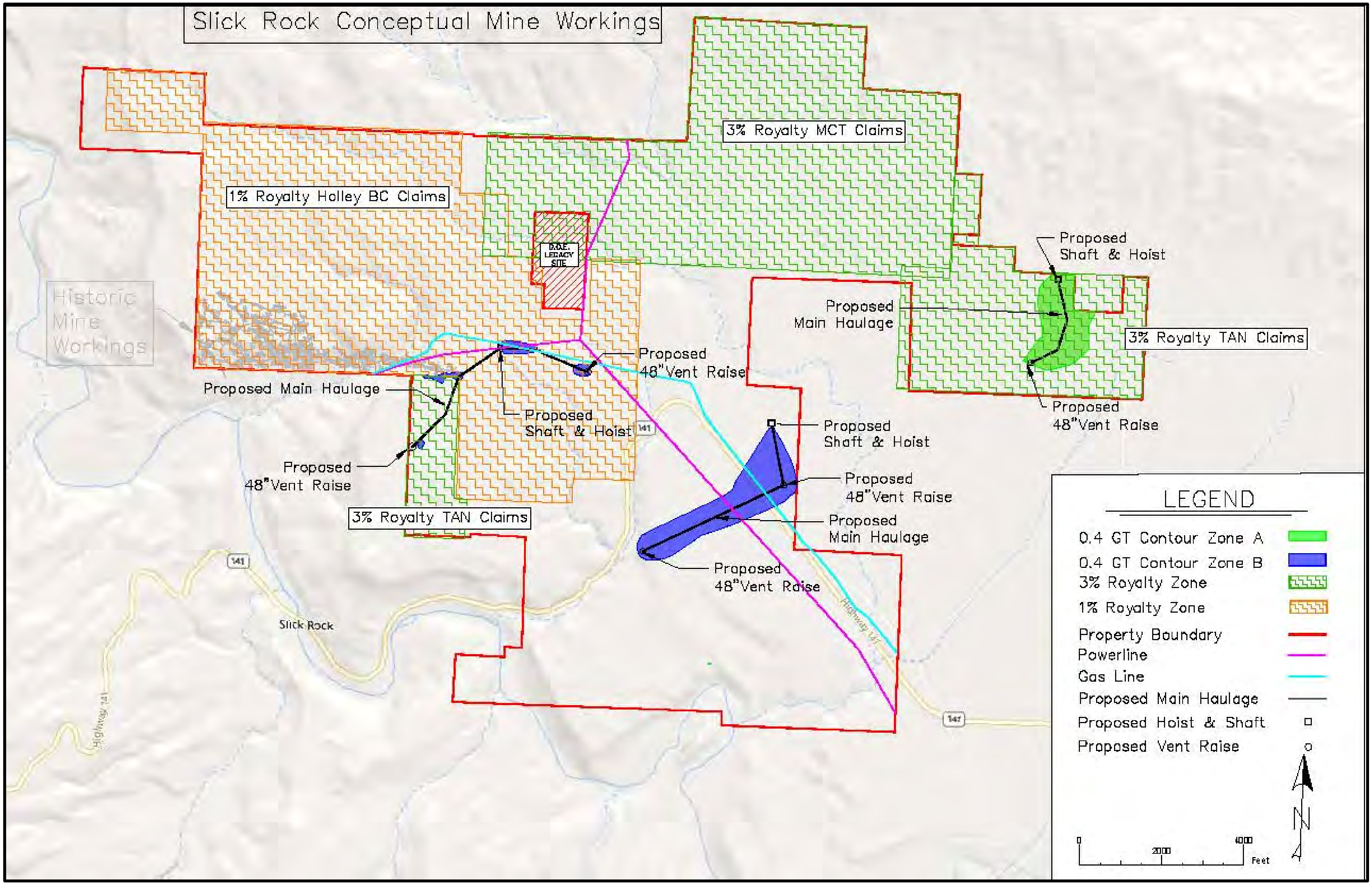


Figure 16.3 - Slick Rock Conceptual Mine Layout



16.2 Mining Methods

Mining methods will be very similar for each mine. Mining will be accomplished via random room and pillar mining methods using single boom jumbo drills for face blast holes drilling and 2 cubic yard Load Haul Dump mining equipment (LHD) used to help maintain clean mucking of mineralized material and of waste. Because of the variable grades, numerous headings are needed to maintain a consistent grade to the mineralized material stockpiles and to achieve the desired tonnage. Each crew will be scheduled to shoot a face 1.5 times per day. This will provide an average of 300 tons/day from each mine complex, for a daily average of 600 tons/day to the mineralized material stockpile while allowing significant time for shift changes, safety training, routine maintenance, and unscheduled breakdowns. The three LHD’s per shift can cycle all of the headings for a maximum of 1,250 feet from the mining face. 10-ton trucks will be used to transfer the muck to the surface.

Velvet Mine

There is an existing 12’ x 9’ decline from the surface, 3,500’ in length at the Velvet Mine. The PEA is based on re-entry and stabilization of this decline to access the Old Velvet Mineralization. Extending from this decline will be an additional 12’ x 9’ decline, 3,300’ in length, that will branch off to access the New Velvet Mineralization. Main entries, secondary entries, and development drifts (8’ x 10’) will be driven for the development and access to the New Velvet Mineralization. Main entries, once within the mineralized horizon, will follow the edge of the mineral deposit leaving one rib in waste rock and the other within mineralized material. This will provide some mineralized material and minimize waste while driving the mains and will provide some support along the main entries upon retreat mine. Secondary entries will be driven off the mains on 100’ centers and extended to the edge of mineralization using long-hole drilling and probes to map the mineralized material as development proceeds. Once the development drifts are finished, full face retreat mining will start working at the back and retreat toward the main entries. Selective mining will be conducted in these areas separating mineralized material from waste.

Agapito Associates, Inc. (AAI) was commissioned by Uranium One in 2008 to complete a study of the ground support and ventilation requirements for the proposed Velvet and Wood mines, (Agapito, 2008). The results of this study are summarized herein. The authors have reviewed this report and concludes that the study was completed in accordance with current industry practices and is applicable to the current PEA and where appropriate.

Based on the geotechnical report (Agapito, 2008), a 10-foot roof span is projected to stand unsupported for about 30 days. The stand-up times, roof spans, and interpretations of strength data suggest a high percentage of pillars can be recovered utilizing a room and pillar mining method at the Velvet and Wood Mine. For the purposes of the PEA, an approximate recovery of 90% was applied based on a retreat pillar extraction/stoping method.

Wood Mine

Several options were considered to access the Wood Mine as summarized on Table 16.3. The preferred alternative is to access the Wood Mine through the workings of the New Velvet Mine. This approach would minimize mine permitting, as a new surface entry would not be needed and all development would be completed underground, thus minimizing surface impacts. The Wood Mine will need additional mine haulage capacity to the Velvet Mine.

Table 16.3 - Options for Entry into the Wood Mine

Option	Max Grade	Length	Decline Size	Tons Muck	Additional Costs
From New Velvet Workings*	1.4%	11,442.9	12' x 9'	85,121	
From Old Wood Decline	21.9%	2,858.0	12' x 9'	21,260	Obtain Permits and Land Rights, Surface Facilities, Old Wood Decline Rehabilitation
From Old Wood Workings	12.8%	2,366.0	12' x 9'	17,600	Obtain Permits and Land Rights, Surface Facilities, Old Wood Decline Rehabilitation
New Portal from Surface	10.0%	9,620.0	12' x 9'	71,561	Obtain Permits and Land Rights, Surface Facilities
New Portal from Surface	12.0%	8,017.0	12' x 9'	59,636	Obtain Permits and Land Rights, Surface Facilities
New Portal from Surface	15.0%	6,413.0	12' x 9'	47,704	Obtain Permits and Land Rights, Surface Facilities
New Portal from Surface	20.0%	4,811.0	12' x 9'	35,787	Obtain Permits and Land Rights, Surface Facilities
New Portal: Shaft from Surface	100.0%	1,112.0	12' diam	8,662	Obtain Permits and Land Rights, Surface Facilities, Hoisting

*Preferred Alternative

Slick Rock

The Slick Rock Mine will use 12-foot diameter main shafts and hoists to access and haul out of the mine workings. There are three proposed shaft and hoist locations. The first main shaft would be located in the east, accessing the resource centered in the A Zone. The second main shaft would access the central portion of the B Zone, and the third access the north-northwest portion of the B Zone adjacent to the historic Burro Mine workings. A total of five 48 inch vent raises would provide for primary ventilation, with one in the eastern A Zone and two per B Zone developments.

Although it would be technically feasible to enter the north-northwest portion of the B zone from the existing Burro workings, no agreement currently exists with the owner of the Burro portals for access. As such it is presumed by this PEA that no access will be given and that all three main shafts would need to be driven from the top of the mesa.

The first hoist would be installed in the easternmost area of the deposit in the A zone while the driving of the central B Zone shaft concludes. After the first hoist is set, construction of the second hoist in the central area would begin. These two hoists will haul from their respective workings concurrently at an average total production of 300 tons/day until the eastern A zone is depleted. Following the depletion of the eastern A Zone, that hoist will be disassembled and relocated to a shaft driven down into the north-northwestern portion of the B Zone. See Figure 16.3 for the conceptual mine layout of Slick Rock Mine.

16.3 Pre-Production Mine Development

Before the production of the Velvet Mine begins, several aspects of the mine must first be running. The mine is currently flooded and will require dewatering. Dewatering is anticipated to take 3 to 6 months at a rate of approximately 250 gpm. In the first two months, the old portal to the Velvet Mine will be rehabilitated. Once the portal is opened, and as dewatering lowers the water level in the main decline, rehabilitation of the main Old Velvet access will begin. In months three and four, access to and stabilization of the existing Vent A will take place. In month five, a second crew will develop access to the west side for further production of Old Velvet, and in months five through ten the first crew will develop a new decline down to the New Velvet. Once these development activities have been completed, production can begin on the New and Old Velvet Mines.

Pre-production mine development for the Wood Mine includes the 11,500 ft access drift from the New Velvet, dewatering of the mineralized area, development work, and up-reaming of mine vents. In addition, permitting for the vents and the dewatering treatment and discharge facilities will be required.

Slick Rock pre-production mine development will include driving two main shafts, installation of hoists, and possible dewatering of the mineralization. After the first hoist is installed, construction of the second shaft and hoist will coincide with the production of the first resource area.

16.4 Mine Equipment

Table 16.4 provides a typical equipment list for a conventional room and pillar mine applicable to the Velvet-Wood and Slick Rock mine complexes.

Table 16.4 - Mining Equipment List

Equipment	Velvet-Wood Quantity	Slick Rock Quantity
Shaft Hoist (12-foot diameter shaft)	N/A	2
Development Jumbo - Single Boom	2	2
Drifter, Hydraulic	3	3
Drifter Feeds	3	3
Jackleg Drill w/ Leg	4	4
Compressor 350 cfm	2	2
LHD 2 cy	2	2
Truck 10 ton	3	2
Pump	2	2
ANFO Loader	3	3
Service Vehicle	1	1
Scissor Lift Truck	1	1
Main Ventilation Fan 5'	4	5
Electric Motor 100 hp	4	5
Accessories for 5' Fan	4	5
Auxiliary Fan 14000 cfm	9	9
Exploration Drill	1	1
Cat 973C Track Loader/Dozer (surface)	1	1
Water Truck 4000 gal (surface)	1	1
Portable Power Center 150 Kva	4	4
Refuge Chamber	2	2

16.4.1 Operating Parameters

The random room and pillar mining method will utilize single boom jumbo drilling, 2 cubic yard LHD face mucking, and 10-ton truck haulage with the associated support equipment. The following are job specific operating parameters that each piece of equipment will be required to meet including but not limited to production rate, working heights, production volumes, turning radius, max operating grades, maintenance schedule, allowable down time, and operating cost.

A summary of equipment cycle times is given in Table 16.5.

Table 16.5 - Summary of Equipment Cycle Times

	Summary of Equipment Cycle Times			
Equipment	Decline & Main Haulage	Production & Development	Velvet-Wood Quantity	Slick Rock Quantity
LHD - 2 cy	62.3 min/round	64 min/round	2	2
Jumbo - Single Boom	378 min/round	199 min/round	2	2
Truck - 10 ton	251 min/round	142 min/round	3	2

16.6 Mine Production Schedule

The mine production schedule is based on two primary mining crews for each mine complex, for a total of four mining crews. The first crew will open the mine and begin production on the New Velvet. The second crew will reestablish access to the Old Velvet Mine and take out mineralized material that is remaining there. The second crew will then continue over to the New Velvet area for mining. The third crew will start with the first shaft and hoist at Slick Rock. The fourth crew will start with the second shaft and hoist at Slick Rock. The GT and T contours were used to develop a block model for mine scheduling, equipment selection, and cost estimations. An annual schedule was developed to estimate the volumes of mine waste and mineralized material extracted from the mines and delivered to the mill, as shown on Table 16.6.

The production schedule is based on the existing tonnage capacity at the mill of 750 tons per day (TPD) or a maximum of 250,000 tons per year. The Velvet-Wood mine is anticipated to operate for 8 years with Slick Rock operating for 15 years. After year 8 additional capacity would be available at the mill.

Current studies have been commissioned and are underway to evaluate increasing the tonnage capacity of the mill.

Table 16.6 - Production Schedule (units x 1,000)

	Totals	Stockpile	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood							
Tons Waste	273		43	55	51	45	45	18	16							
Tons undilluted	757	76	39	65	74	119	132	148	104							
Tons Product	795	80	41	68	77	125	139	156	109							
Grade % U3O8	0.308	0.157	0.371	0.304	0.339	0.281	0.358	0.394	0.218							
Pounds Contained U3O8	4,889	251	301	414	524	701	993	1,229	476							
Grade V2O5	0.409	0.000	0.519	0.425	0.474	0.393	0.502	0.552	0.305							
Pounds V2O5	6,493	0	421	580	733	981	1,391	1,720	667							
		Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock B	Slickrock B	Slickrock B	Slickrock B	Slickrock B
Tons Waste	1,340	62	124	124	124	93	77	93	93	124	116	70	70	70	70	31
Tons undilluted	1,584	75	150	150	150	113	94	113	113	150	140	75	75	75	75	34
Tons Product	1,663	79	158	158	158	118	99	118	118	158	147	79	79	79	79	36
Grade % U3O8	0.22	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.221	0.200	0.200	0.200	0.200	0.200
Pounds Contained U3O8	7,256	352	705	705	705	529	440	529	529	705	651	316	316	316	316	142
Grade V2O5	1.31	1.339	1.339	1.339	1.339	1.339	1.339	1.339	1.339	1.339	1.329	1.202	1.202	1.202	1.202	1.202
Pounds V2O5	43,533	2,114	4,228	4,228	4,228	3,171	2,643	3,171	3,171	4,228	3,908	1,897	1,897	1,897	1,897	854
Tons Total	2,456	159	198	226	235	243	237	272	228	158	147	79	79	79	79	36
Pounds contained U3O8	12,144	603	1,006	1,119	1,228	1,229	1,434	1,757	1,005	705	651	316	316	316	316	142
Pounds Contained V2O5	50,026	2,114	4,649	4,808	4,961	4,152	4,033	4,891	3,838	4,228	3,908	1,897	1,897	1,897	1,897	854

16.7 Mine Labor

Qualified mine labor is available in the region. Table 16.7 summarizes the personnel requirements by classification needed to meet the production estimates as summarized in Table 16.6.

Table 16.7 - Labor Requirements

Labor Requirements		**Velvet-Wood**		**Slick Rock**	
Hourly Labor Requirements	Shifts/year	Personnel Per shift	Total	Personnel Per shift	Total
Jumbo Miners	3	2	6	2	6
Jumbo Helper	3	2	6	2	6
Utility Miners (Const., Utilities, etc.)	3	1	3	2	6
UG Laborer	3	1	3	2	6
LHD Operators	3	1	3	2	6
UG Truck Operators	3	2	6	2	6
Surface Operators	3	1	3	1	3
Exploration Drillers	1	2	2	2	2
Electricians	3	1	3	1	3
Mechanics	3	1	3	1	3
Control Room Operator (Dispatcher)	3	1	3	1	3
Warehouse Laborer	3	1	3	1	3
Subtotal Hourly		16	44	19	53
Salaried Personnel Requirements					
Chief Engineer/Manager	1	1	1	1	2
Mine Foreman	1	1	1	1	2
Foreman/Shifter	3	1	3	1	6
Engineers and Surveyors	1	2	2	2	4
Chief Geologist	1	1	1	1	2
Geologists	3	1	3	1	6
Maintenance Supt.	1	1	1	1	2
Technicians	1	2	2	2	4
Accountants – Clerk	1	1	1	1	2
Purchasing Agent	1	1	1	1	2
Personnel/Safety Manager	1	1	1	1	2
Subtotal Salary		13	17	13	17
Total Annual Payroll		29	61	32	70

16.8 Mine Support and Utilities

Mine facilities located on the surface would include a mine office, warehouse, and workshop, change room and dry facility, a lined storage area for mined product, storage for explosives, and various appurtenances as summarized in Table 16.8. Utilities would include electrical power, a water supply, and a wastewater disposal system. Water would be supplied via treated mine wastewater and stored in a stock tank. Potable water will be trucked in as needed.

Table 16.8 - Surface Facilities

Mine Surface Facilities	Velvet-Wood	Slick Rock
Computer & Office Furniture	1	1
Office	1	1
Change Room and Dry	1	1
Workshops	1	1
Civils (Footers) for Buildings	1	1
Magazines	1	1
Fuel Tank	1	1
Mined Product Bin	1	1
Fencing and access control	1	1
Workshop Tools	1	1
Safety Equipment	1	1
Septic Tank	1	1
Spill Mats (Oil Areas)	1	1
Water Supply System	1	1

16.9 Mine Ventilation

Agapito performed a series of mine ventilation analyses to facilitate the proposed mine's operating in compliance with applicable air quality regulatory standards (Agapito, 2008). Particular emphasis in the design was placed on the main fan and raise locations that should, with appropriate controls, enable the mine to meet applicable Mine Safety Health and Administration (MSHA) ventilation requirements. The primary contaminants of concern for the ventilation system include radon, diesel particulate matter (DPM), diesel exhaust gases (CO, CO_2, NOx, and SOx), blasting fumes, and silica dust. Once the mine is operational, a sampling program should be instituted to identify and quantify the airway contaminants.

Based on the analysis of the likely equipment and production demands, the estimated quantity of air needed to effectively manage the DPM is at least 166 thousand cubic feet per minute (kcfm). This volume of fresh air will allow an area 10 feet by 8 feet by 31,000 linear feet long to be replenished with fresh air every 15 minutes for control of radon daughters. While no site-specific data concerning radon is available at this time, this rate of air exchange should be a good first approximation until empirical testing can take place.

Section 17: Recovery Methods

17.1 Summary

The Shootaring Canyon mill is an existing facility which was constructed circa 1981 and operated sporadically until 1982. As discussed in Section 20, the mill has an existing radioactive materials license which would need to be amended to allow operations to resume. Although the mill has been on a care and maintenance program, various components have been salvaged and sold, including the Counter Current Decantation (CCD) thickeners and various pumps and related equipment. In addition, some of the equipment units, such as the diesel generators, are outdated and may be not useable. Nonetheless, the main process building was well-designed and is generally in very good condition.

For the purposes of this PEA, the capital and operating/maintenance cost estimates for mineral processing at the mill site were confined to the original conventional grinding and agitated leaching circuit, followed by yellowcake precipitation, drying, and drum filling. Two options were considered.

1. The first optin envisioned renovating ("refurbishing") the original equipment, including replacements where needed, and retaining the original building - at a significant net savings of roughly $4 million.
2. The second option, retaining the original building and installing new equipment was used in the PEA as a conservative measure. Although more expensive than refurbishment, this option would include current state-of-the-art equipment and best available technology, which is in keeping with Anfield's corporate philosophy, current regulatory requirements, and conservative guidance.

In both cases, the assumed mining plan includes mine production from the Velvet-Wood and Slick Rock mines plus processing of stockpiled material. Also, both cases include vanadium recovery, beginning with leaching at a higher free acid concentration (pH 0.8 to 1.2 versus 1.5 to 2.0) to ensure satisfactory extraction of vanadium. Vanadium recovery from uranium solvent extraction raffinate assumes installation in a relatively small new building near the existing process building.

The Shootaring Canyon Mill was constructed by Mountain States Engineers (Tucson) and was among the last 2 or 3 conventional mills built before the collapse of the uranium industry. Its design benefited from two decades of revolutionary changes, such as solvent extraction, and many evolutionary improvements based on an accumulation of industry-wide experience in operation and maintenance of dozens of mills. Among the most up-to-date features were the following:

- Semi-autogenous grinding ("SAG milling") of run-of-mine ore replaced crushing, screening, and rod mill grinding, reducing requirements for capital, energy, operating & maintenance labor, and steel grinding media.
- Conventional grinding circuit particle size classification with rake or spiral classifiers or hydro-cyclones was replaced with a single DSM-type sieve bend that enabled gravity return of oversize to the SAG mill, while sieve undersize was delivered by gravity to the leaching circuit.

- Laboratory tests had revealed that uranium leaching kinetics were improved by increased temperature, so required heating was provided by circulation of process solutions through the radiators and cylinder blocks of on-site diesel generators.
- Some newer mills had been built with two-stage leaching which contacted fresh ore with fresh leaching solution for 2 to 4 hours in the first-stage tanks, then completed the leach with 12 to 16 hours retention in second-stage tanks at a lower free acid concentration and lower percent solids. This design generally led to lower overall acid consumption and was incorporated in the mill.
- The leach tanks were made of wood staves with external compression bands, resulting in inexpensive construction, good acid resistance, and freedom from leakage after presoaking in water.
- A six-stage counter-current decantation (CCD) circuit was installed to maximize recovery of dissolved uranium at +99% washing efficiency. Deep tanks were used, with a high-rate design embodying inter-stage mix tanks and slurry introduction into the settling zone, rather than old-style feeding into a center well.
- Advanced process condition sensors and automatic control instruments were installed throughout the plant and interfaced with both local control stations and centralized process data recording.
- Precipitated yellowcake was centrifuged after thickening and prior to filtering and thermal drying.

17.2 Shootaring Canyon Mill Partial Refurbishment vs. All New Equipment

An internal report entitled "Definitive Cost Estimate for the Restart of Shootaring Canyon Mill Ticaboo, Utah" was completed on March 28, 2008, by Lyntek, Inc. (Lyntek, 2008), and covered the restart of the mill which has not been operated since 1982. The Lyntek estimate proposed complete refurbishment of the mill and included some purchases of new equipment, including countercurrent decantation (CCD) thickeners, pumps, instrumentation, and scrubbers, with an allowance for personnel hours and materials for refurbishing or repairing equipment.

An alternative to refurbishing is complete removal of old equipment and replacement with new equipment, but within the original building. The original building is serviceable and a new one would cost approximately $4 to $7 million plus the cost of demolition of the original structure.

In either case, the basic processing flowsheet would be preserved, but some equipment types that were originally installed would be supplanted with the current generation. An example would be acquisition of a fully automated drum filling station capable not only of accurate weighing, but also of automated removal and replacement of the drum locking clamp ring, reducing exposure of personnel to dust.

Provisionally, the uranium section of the facility will follow the original design. The mill was designed by Mountain States Engineers, and construction was completed circa 1981 for the owner/operator, Plateau Resources. The design capacity was 750 short tons per day (tpd) of uranium ore. Although the ore contained potentially leachable vanadium, a vanadium recovery circuit was not designed or built.

Owing to the collapse of the domestic uranium industry, the mill was operated for only a brief period. Following cessation of production, the equipment was drained, cleaned, and "mothballed", but some pieces of equipment, notably pumps and thickeners, were removed and sold. The following paragraphs describe the processing flowsheet as designed and built and depicted in Figure 17.1, "Original Shootaring Canyon Mill Flowsheet".

Run-of-mine (ROM) ore was hauled by truck and dumped on a graded storage area from which it was reclaimed by a 3 cubic yard front-end wheel loader and dumped onto a grizzly with 14-inch square openings. Grizzly oversize was removed for secondary breaking, and undersize fell into a surge bin with approximately 75 tons live capacity. Coarse ore was withdrawn by a variable speed apron feeder and discharged onto a steeply inclined stationary grizzly with 3-inch square openings. Grizzly undersize fell onto a 42-inch wide by 316-foot mill feed conveyor, providing impact and wear protection from falling rock. Dust released during coarse ore handling was drawn through a wet scrubber by an exhaust fan. The scrubber slurry was pumped to the downstream grinding and classification circuit.

Coarse ore was conveyed beneath a metal detector and over a belt scale to a 12-foot diameter by 6½-foot long semi-autogenous grinding (SAG) mill driven by a 250 Hp motor. About 8 to 10 percent of the mill volume was charged with 6-inch diameter cast steel balls to crush resistant ore fragments. A slurry of ore particles at about 65 to 70% solids (by weight) overflowed through the SAG discharge trunnion into a pump sump and was pumped to a cluster of four DSM sieve bends (stationary banana-shaped screens) with 28-mesh aperture slots between self-cleaning wedge wires. Screen oversize was returned by gravity to the SAG feed spout along with sufficient process water to maintain the desired discharge density. The design circulating load in the grinding/classification circuit was 200 percent.

Screen undersize flowed by gravity into a sump and was pumped to two agitated leach feed holding tanks. Made of wood staves, the tanks were 20 feet in diameter by 28 feet high with a slurry capacity of 60,000 gallons apiece. The stave walls' exteriors were pre-soaked, then continuously supplied with water to prevent drying and shrinkage of the staves. Each tank had a single agitator shaft with two marine-type propellers and a 50 Hp gear-reduced drive.

During leaching, tetravalent uranium was oxidized to the soluble hexavalent state with sodium chlorate, $NaClO_3$, and complexed with sulfuric acid. As was commonly done for ores with relatively high acid consumption, the leach circuit was 2-stage. The first stage contained three agitated tanks 14 feet in diameter by 18 feet high with an effective volume of 16,120 gallons apiece, and providing a total retention time of 2 hours at 29% solids. During this stage, the ore slurry was mixed with overflow from the #1 countercurrent decantation (CCD) thickener to which was added sufficient sulfuric acid and sodium chlorate to maintain an optimum pH and EMF. To this thickener and the remainder of the CCD circuit, a flocculent solution was added as needed to maximize underflow density and to reduce overflow turbidity. Partially leached slurry from the first stage leach circuit was pumped to a thickener with a 19.5-foot diameter and 8.75-foot side-wall height. The thickener underflow at about 50 percent solids was pumped to the second stage leach circuit.

The second stage leach circuit consisted of four agitated tanks 20 feet in diameter by 24 feet high with an effective volume of 46,400 gallons apiece, providing a total retention time of 16 hours at a design density of 48.8% solids. Sulfuric and sodium chlorate to maintain optimum pH and EMF were again added and the design criteria specified a total of 140 pounds of 93% H2SO4 and 1.171 pounds of $NaClO_3$ per dry ton of ore. It was anticipated that 93% of the uranium in the ore would dissolve. Although the presence of potentially soluble vanadium from carnotite mineralization in the ore was recognized, the leaching conditions were not intended to maximize vanadium extraction and a vanadium recovery circuit was not designed.

Maximum economic recovery of dissolved uranium from the second stage leach circuit discharge was to be achieved by washing of the leached residue in a 6-stage CCD thickener configuration. Leached residue slurry was pumped to the agitated mix box on the #1 CCD thickener and mixed with solution overflowing the #2 CCD thickener. The first five thickeners were high-rate type, 26¼ feet in diameter by 8 feet side wall height, with a design underflow slurry density of 50% solids by weight. Recycled solvent extraction raffinate entered the #6 CCD thickener mix box where it combined with #5 CCD thickener underflow. In this manner, washing solution advanced through the circuit countercurrent to the flow of solids.

In order to maximize the underflow density of the last CCD thickener, that unit was the high-density type, 26¼ feet in diameter x 28.2 feet side-wall height with a design underflow slurry containing up to 60% solids by weight. This slurry was pumped to the tailings impoundment pond from which clear supernatant water could be reclaimed and pumped back to the mill's process water supply.

Overflow from the 1st stage leach discharge thickener was pumped to a clarifier-type thickener 27 feet in diameter by 18 feet side-wall height. Underflow slurry was periodically pumped to the head of the 2nd stage leach circuit while the overflow, which was intended to contain no more than 50 parts per million (PPM) solids, was pumped to three sand-type filters. The filters were operated in parallel and equipped for automatic back-washing. The design hydraulic capacity was 5 gpm/ft2 and each filter contained 38 square feet of effective area. Backwashed solids were pumped to the head of the 2nd stage leach circuit. The filtrate containing no more than 10 ppm solids was pumped to two pregnant leach solution (PLS) storage tanks, each with 23,000 gallons capacity.

Concentration and purification of uranium in the PLS were accomplished simultaneously with liquid ion exchange ("solvent extraction"), wherein aqueous uranyl sulfate ions were contacted with an organic liquid containing an extractant, a modifier, and a diluent. The extractant selected for the plant was a tertiary amine, Alamine 336. The modifier was a long-chain alcohol, isodecanol, chosen to improve phase separation and solubility of the amine in the diluent. The diluent was a type of kerosene with properties, such as a high flash point, that were specific to the needs of SX.

In practice, the uranyl sulfate was exchanged out of the aqueous PLS into a tertiary amine complex that remained dissolved in the organic phase. The amine concentration in the organic phase was maintained at 1.0 volume percent per gpl of U_3O_8 in the PLS. Isodecanol concentration was 5.0 volumetric percent and diluent made up the remainder. Mixer retention time was 2.0 minutes and the settler area was designed for a specific flow of 1.25 gpm/ft2. Organic flowed countercurrent to the aqueous phase and was recycled from each extraction settler and combined with the organic from the next stage in order to maintain the desired organic to aqueous (O:A) ratio in each mixer. After mixing, the resulting emulsion of fine droplets of the organic and aqueous phases overflowed from the mixer into its settler, where quiescent laminar flow permitted droplets to coalesce and allowed the denser aqueous phase to settle beneath the lighter organic phase. The uranium-loaded organic from the 1st stage extraction settler overflowed that settler's weir and was pumped to the loaded organic storage tank. The aqueous phase flowed from the 1st stage settler into the 2nd stage mixer where it was contacted with organic from the 3rd stage settler. The aqueous stream exiting the 4th stage settler contained only a low concentration of uranium governed by equilibrium chemical relationships and flowed to the raffinate storage tank. From that tank, the raffinate was pumped to the 6th stage CCD thickener's mix box for washing the leached residue.

By the mid-1970s, some uranium operations had abandoned sodium carbonate ("soda ash") stripping in favor or so-called "controlled pH stripping" using ammonium sulfate solution whose pH was regulated by addition of ammonium hydroxide or anhydrous ammonia. This technique was the basis for the design of the Shootaring Canyon stripping circuit. Controlling the pH between about 4.0 and 4.3 was critical; below pH 4.0, stripping efficiency was inadequate and above pH 4.3, phase separation would have been poor and emulsions would have formed due to hydrolysis of uranium. A major advantage offered by this approach was the ability to make yellowcake containing very little sodium.

In a countercurrent manner identical to that used in extraction, stripping was conducted in four mixer/settler stages. Organic loaded with uranium was pumped from the storage tank to the 1st stage strip mixer along with aqueous ammonium sulfate solution from the 2nd stage strip settler. As in the extraction circuit, pumping mixer impellers were used to advance organic and aqueous streams between stages and to recycle organic as needed. Ammonia was added to each strip stage mixer to control pH. Organic overflowing the 3rd stage settler entered the 4th stage mixer along with barren (aqueous strip) solution, and organic overflowing the 4th stage settler was pumped to the barren (stripped) organic storage tank.

Amine extraction of uranium PLS is not entirely selective, with the result that there will be co-extraction of other metals including molybdenum and vanadium if they dissolve during leaching. In order to prevent an accumulation of these impurities in recirculating organic, the plant contained a single mixer/settler unit for "scrubbing" the stripped organic with aqueous sodium carbonate. The scrubbed organic was then pumped to a surge tank for re-use in the extraction circuit. Most of the aqueous phase was recycled to the scrub mixer to maintain a low O:A ratio, and a bleed stream was pumped to the tailings or evaporation ponds.

Precipitation of yellow cake was based on contacting the pregnant ammonium sulfate strip solution with anhydrous ammonia gas. First, the solution from SX was pumped through two carbon columns, arranged in parallel, to remove residual entrained organics. The PLS was then pumped through a heat exchanger, indirectly contacting diesel generator coolant water, exiting at about 80º C (176º F) into three agitated precipitation tanks arranged in series. Each precipitation tank had temperature control valves supplying hot water and the total residence time was 9 hours.

Precipitation was accomplished by direct neutralization with ammonia gas to a final pH in the range 6.5-8.0 at a design consumption of 0.18 lb NH_3 per pound of U_3O_8. Ideally, the product would be ammonium diuranate ("ADU"), $(NH_4)_2 U_2O_7$, although the precipitate will typically be a mixture of diuranates, basic uranyl sulfate, $(UO_2)_2SO_4(OH)_2$, hydrated oxides, and adsorbed impurities. Actual composition depends on pH and temperature, as well as PLS composition.

The precipitate slurry was pumped to a thickener 12 feet in diameter with 4-foot side-wall height. Thickener overflow was returned to a small surge tank ahead of precipitation and the underflow was pumped to two vacuum drum filters 3 feet in diameter by 3 feet wide, arranged in series with a "repulping" tank after the first stage. A centrifuge was available as an alternative. Filter cake fell into a trough, thence to a Moyno progressive cavity pump that extruded the thick paste into a multiple-hearth calciner with six 5-foot diameter rotating hearths. The calciner was designed for a maximum operating temperature of 870° C (1,600º F).

Drying of the precipitate occurred on the top hearth, then calcining up to about 650-700º C would have yielded a very dry yellowcake product that was essentially devoid of ammonia, sulfate, and chloride. The calciner and its enclosure envelope were designed to be operated under a negative pressure to prevent escape of yellowcake into the mill building. A wet scrubber on the exhaust gases captured fine dust and the slurry was pumped to the yellowcake thickener.

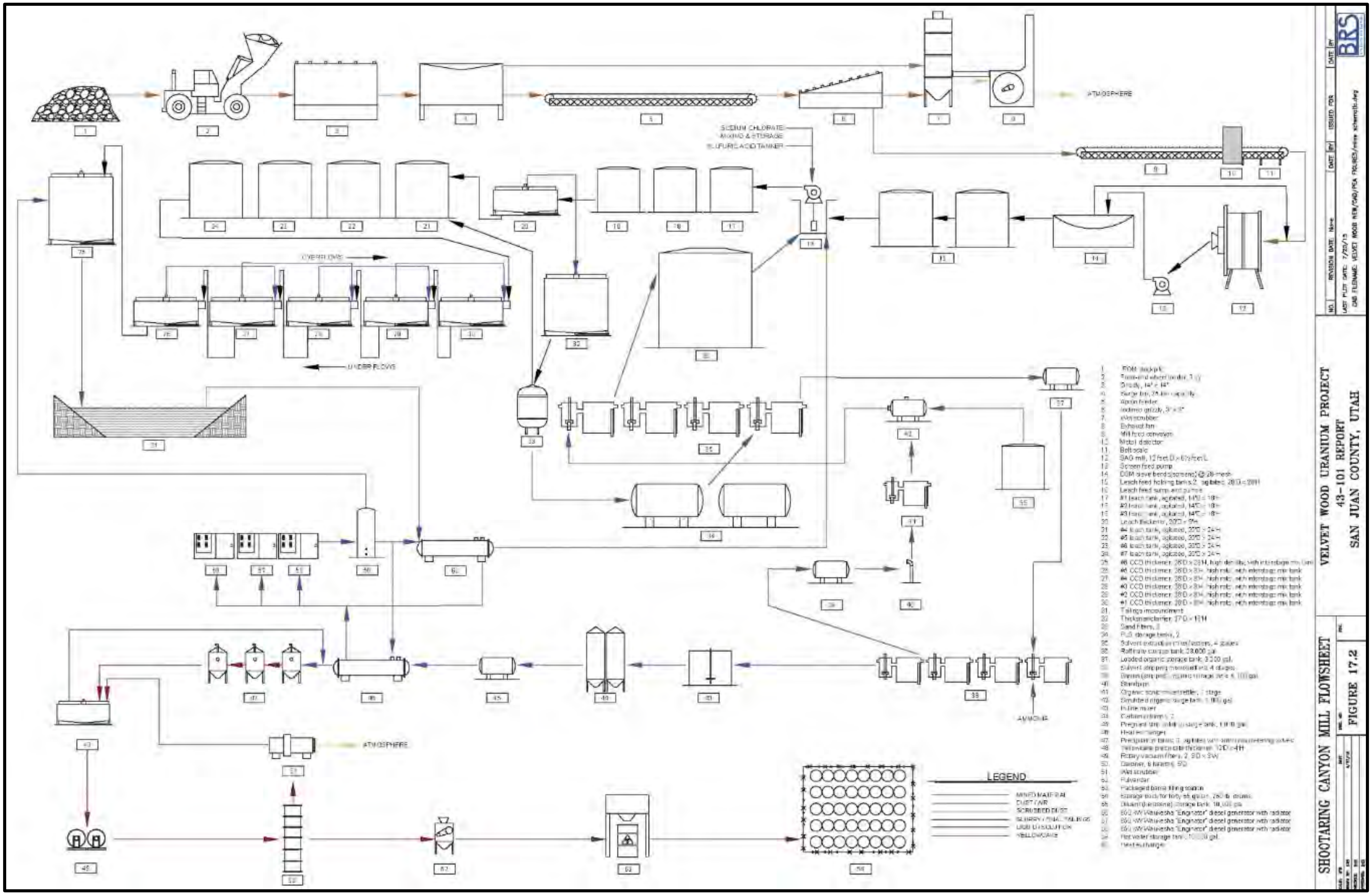
Calcined yellowcake, nearly pure U_3O_8, was passed through a pulverizer to eliminate lumps before being conveyed to a barrel sitting on a vibrator to ensure compaction during filling. Drums filled to about 800 pounds, including tare weight, passed over a roller conveyor to a batch scale, and then had lids attached and were taken to the product loading dock.

Leached and washed residues (tailings) were pumped to an impoundment cell located about 200 yards southwest of the plant. The impoundment net volume was 2,600-acre feet and remains capable of holding 5,475,000 dry tons of solids with an ultimate surface area of approximately 70 acres. A drainage network was installed in the bottom of the impoundment with the intent that a prescribed placement procedure would be followed that would avoid formation of slimes pockets.

Three Waukesha 850 kW "Enginator" diesel generators provided electric power to the plant with one of the units on standby. Expected fuel consumption was 64.8 gallons per hour for an average plant energy demand of 924 kW. Radiators and engine blocks were in closed loop with heat exchangers that allowed non-contact heating of leaching and precipitation solutions. These engines may no longer be capable of upgrading to current air quality standards and may be replaced, following a comprehensive evaluation.

Figure 17.1 depicts the original flowsheet and describes, with few exceptions, the future uranium processing flowsheet.

Figure 17.1 - Original Flowsheet for the Shootaring Canyon Uranium Circuit



17.3 Vanadium Recovery Circuit

A facility for the recovery of vanadium is included in the mineral processing CAPEX and OPEX estimates herein. The depleted aqueous solution from uranium solvent extraction, the uranium raffinate, will serve as the feed for vanadium concentration. A sludge thickener will be used to enable settling and densification of particulate matter and the thickener underflow slurry will be discharged to the tailings facility. A solvent extraction (SX) circuit will concentrate the vanadium into a vanadium product liquor (VPL). The VPL will then flow to a conversion tank, anhydrous ammonia will be added, and steam will be used to indirectly heat the solution to above 180º F, promoting formation of dissolved ammonium metavanadate ("AMV"). The AMV cake will be dried in a fuel-fired rotary dryer, then treated in one of three ways, depending on market requirements:

1. The AMV may be packaged and sold;
2. It may be fed directly to a multiple-hearth calcining furnace ("deammoniator"), melted in a fusion furnace, tapped into a water-cooled casting wheel, and packaged as "black flake" containing a minimum of 98.0 %V_2O_5;
3. It may be dissolved with dilute sulfuric acid in an "acidulation" tank, followed by addition of ammonium hydroxide to a neutralization tank, from which the liquor would flow through a water-cooled heat exchanger to a crystallizer. The slurry of re-crystallized AMV would be fed to a washing belt filter, thence to the deammoniator, fusion furnace, and casting wheel described above. This product could contain up to 99.9% V_2O_5 and would also be called "black flake".

A simplified preliminary block flow diagram is presented below as Figure 17.2. Some elements of the flowsheet may change during detailed engineering when equipment alternatives will be considered in the interests of increased metallurgical efficiency, improved health and safety for personnel, and reduced costs.

Figure 17.2 - Vanadium Concentration Circuit, Page 1 of 2

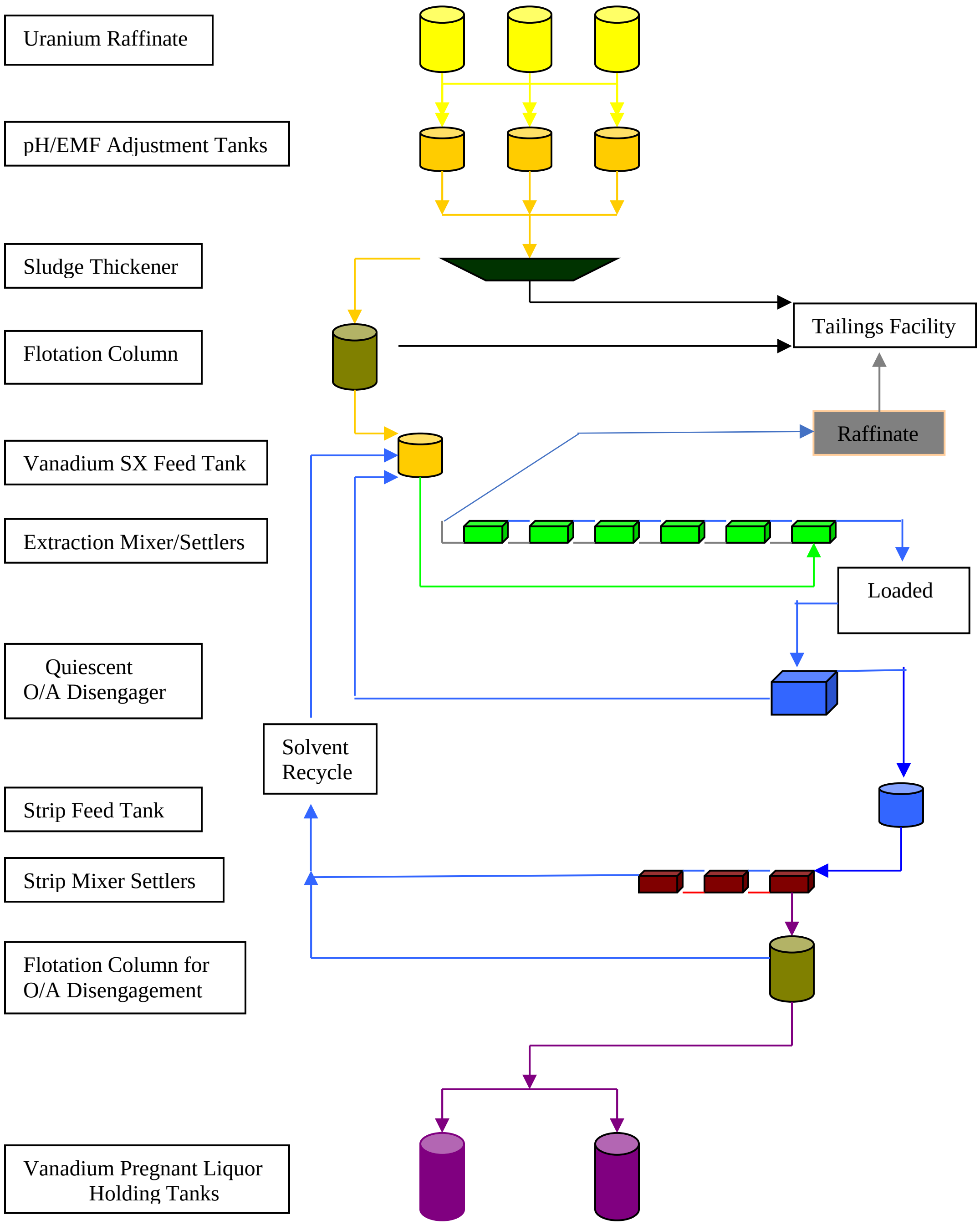


Figure 17.3 - Vanadium Purification and Precipitation Circuit, Page 2 of 2

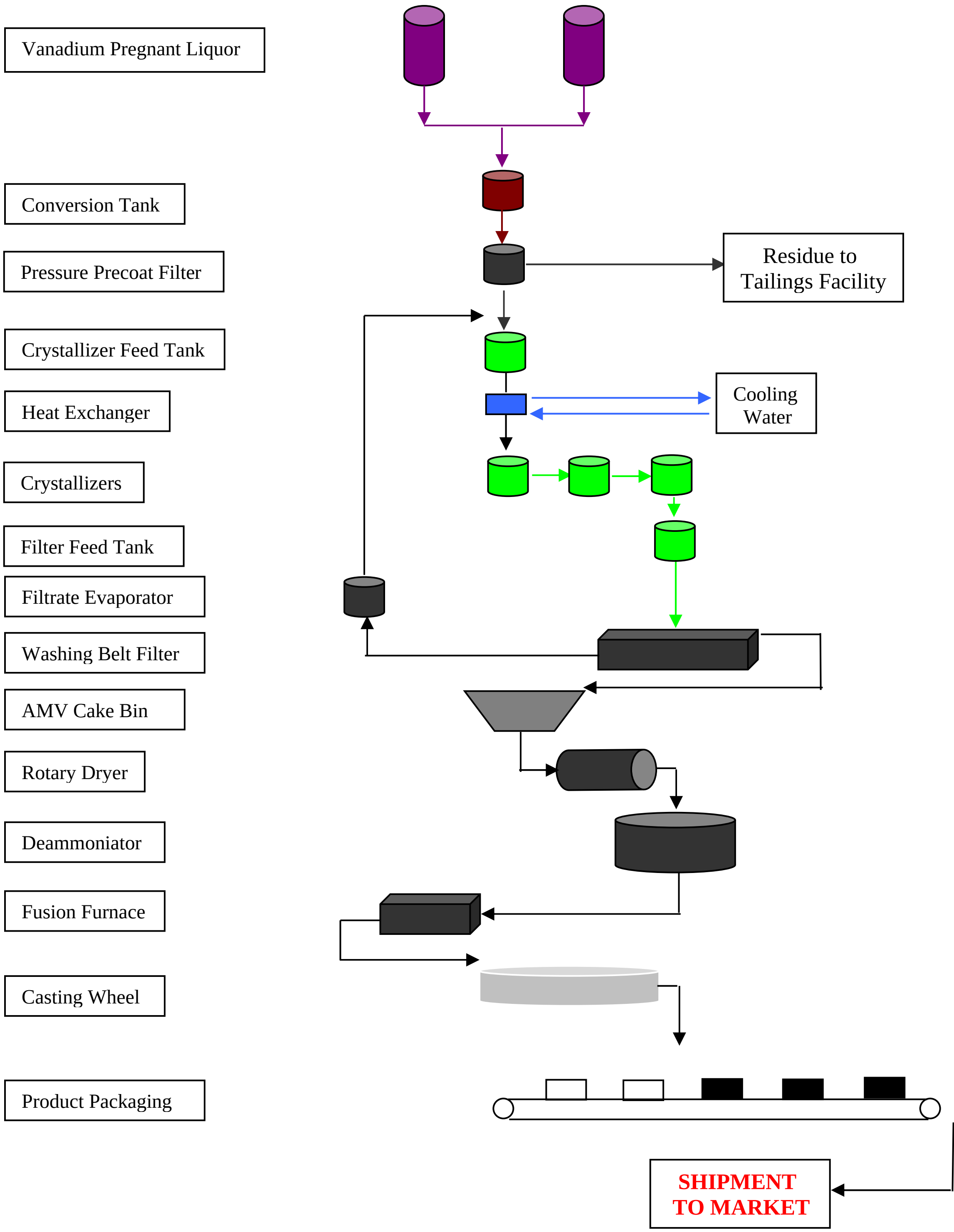
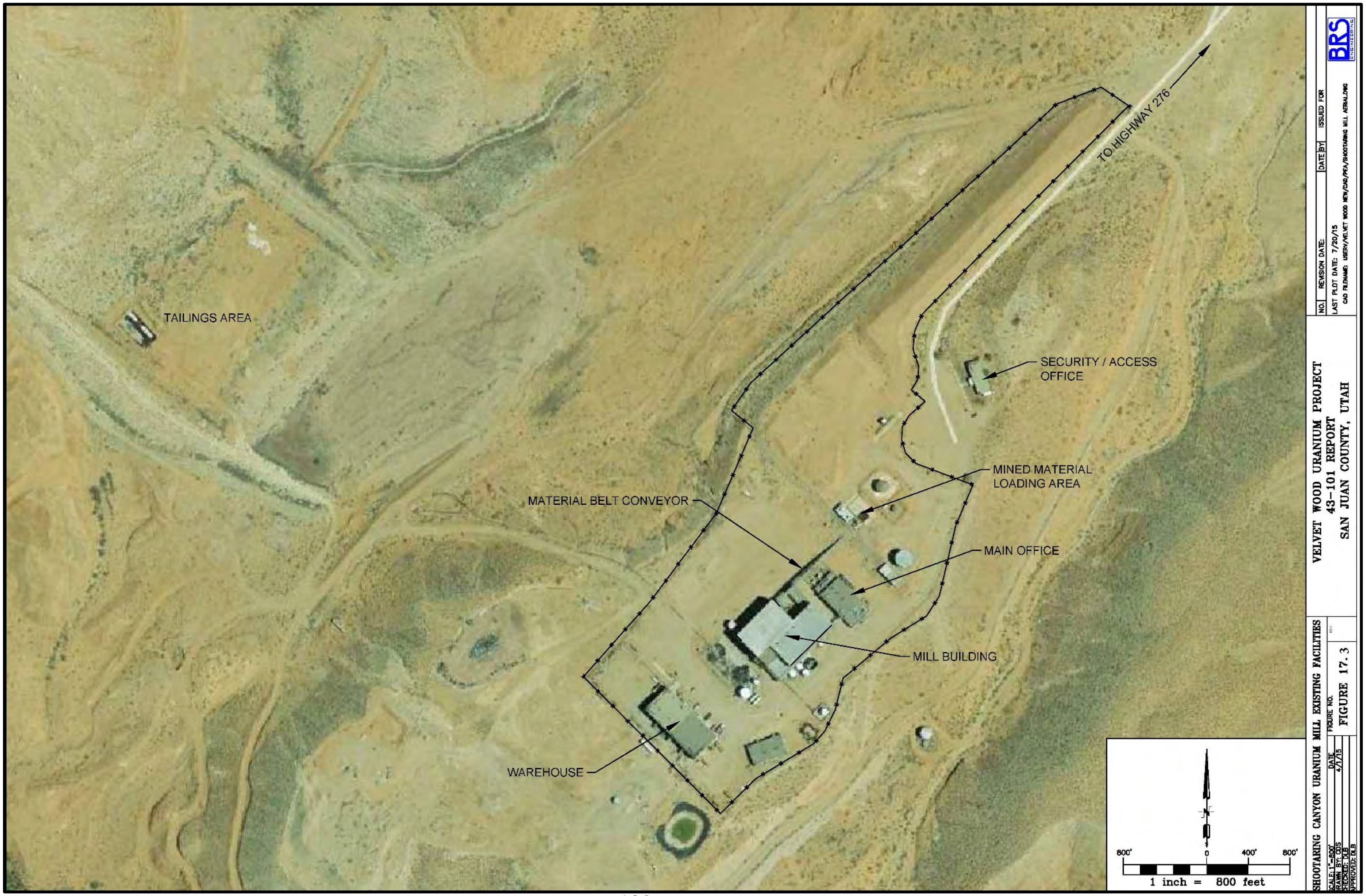


Figure 17.4 - Shootaring Canyon Property with Existing Facilities at Ticaboo, Utah



Section 18: Project Infrastructure

18.1 Existing Infrastructure

Existing conditions and infrastructure are shown on the following figures for the respective areas of the project.

- Figure 17.3 – Shootaring Canyon Mill
- Figure 18.1 – Velvet-Wood Mine
- Figure 16.3 – Slick Rock Mine

18.2 Access

The Shootaring Canyon Mill is located approximately 2 miles west of Utah Highway 276 and approximately 3 miles north of Ticaboo, Utah. By road, the distance is approximately 180 miles from the mill to the Velvet Mine area. Access to the mill is via paved highways with the exception of the 2-mile gravel road from the mill to Highway 276.

Portions of the Velvet deposit were previously mined and there is an existing access road and powerline to the portal location. The Velvet portal is accessible via existing roads beginning with the Big Indian Road, a paved road that exits U.S. Highway 191 about 19 miles north of Monticello, Utah or 34 miles south of Moab, Utah. The Big Indian Road extends eastward and loops into the Lisbon Road to serve properties in the Lisbon Valley area. A gravel road, San Juan County Road 112 (Williams Fork) exits the Big Indian Road about 5.5 miles east of its intersection with Highway 191. A private access road connects with County Road 112 about 6 miles southeast of its intersection with the Big Indian Road. The Velvet Mine portal is about one mile northeast along this road.

The Wood mine area is located about 3 miles east of Velvet along County Road 112 and is also accessible from the east via the Lisbon Valley Road and County Road 112. Access to the site is via existing dirt two-track roads.

The Slick Rock area is crossed by Colorado State Highway 141, a paved 2 lane highway providing major access to the site. From Highway 141, gravel county roads and existing dirt and two-track roads provide secondary access to the site.

18.3 Power and Utilities

No line power is available at the Shootaring Canyon Mill. When the mill was in operation, power was provided by diesel generators. On-site power generation will be necessary for the mill.

A power line terminates approximately 0.6 miles NNW of the old Velvet Mine portal pad, which is located in the SE ¼ of Section 3, T 31S, R25E, as shown in the Figure 18.1, Velvet-Wood Mine Surface Facilities Overview Map. All electricity for the mine and surface facilities will be provided by this power line.

For the Slick Rock area, gas pipelines crossing the project area are shown on the USGS base map. Electrical powerlines follow the major access roads, Figure 16.3. Slick Rock is an unincorporated locality. Residents have utility and phone service. Utility service was also once provided to the Burro and other mines in the area.

18.4 Water

Non-potable water is available from wells at the Velvet mine and Shootaring Canyon Mill sites for operations and fire suppression. Potable water will be supplied by commercial bottled water.

For the Slick Rock and Wood, detailed investigation of potential water sources has not been completed. As mineral processing will be accomplished offsite the only water demand will be for industrial and potable use at the mine site and as such the demand is modest. The preferred alternative for process water is to utilize water developed from the dewatering of the mine, estimated for cost purposes at 200 gpm, which in turn would reduce costs related to water treatment and discharge. This water may not be suitable as a potable water source for the office and dry facility. Potable water sources could be developed from local ground or surface water sources and/or hauled into the site.

18.4 Surface Mine Facilities

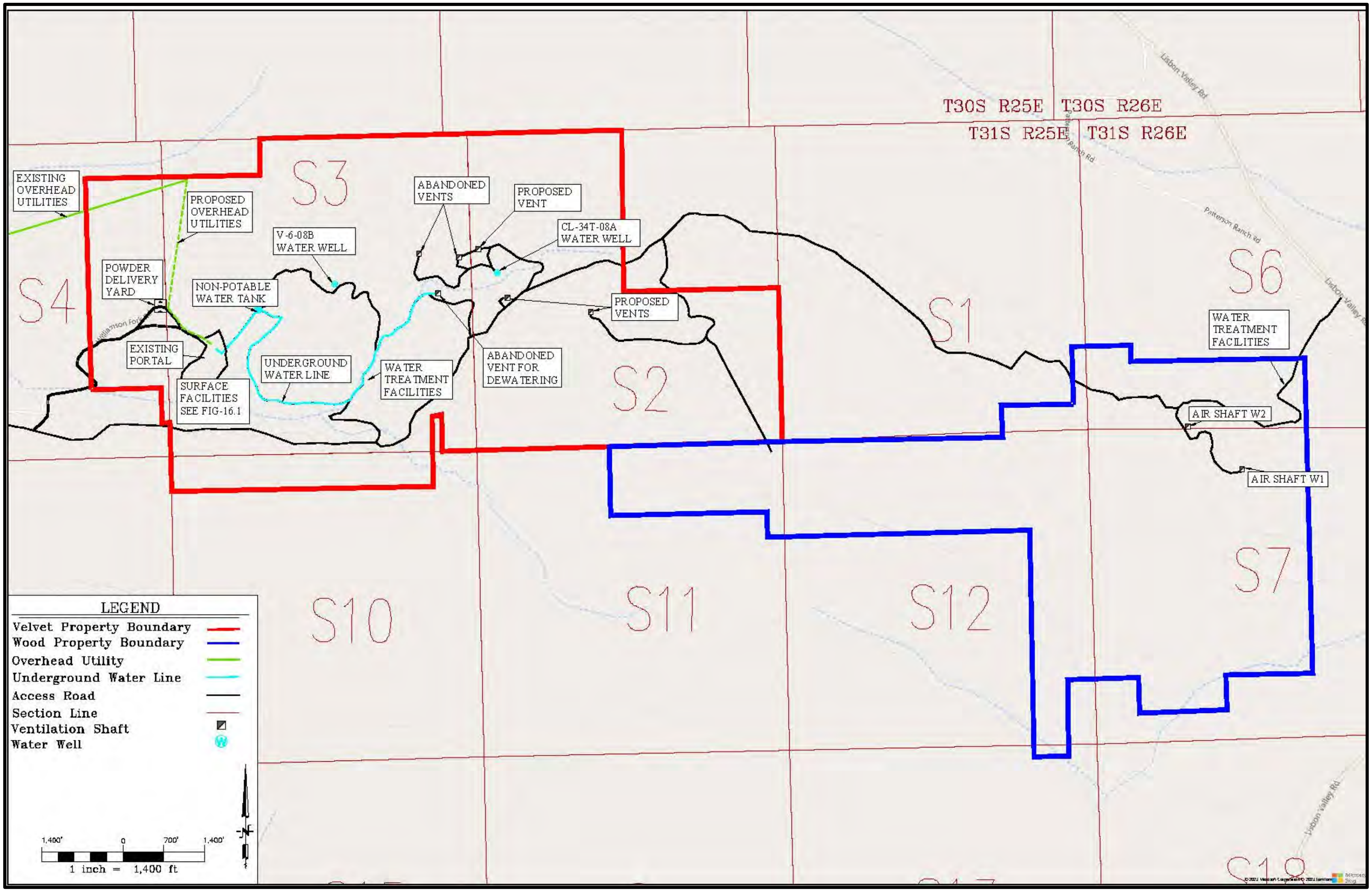
Surface mine facilities for Velvet-Wood (existing and planned) are described in Section 16 and are shown on Figure 16.1. Mine facilities located on the surface would include a mine office, warehouse, and workshop, change room and dry facility, a lined storage area for mined product, storage for explosives, and various appurtenances as summarized in Table 16.8. Utilities would include electrical power (existing at site), a water supply, and a wastewater disposal system. A septic system would be permitted and constructed for wastewater.

For the Slick Rock area, mine support facilities will consist of an office, mine shop and warehouse, and a dry facility. In consideration of the remote nature of the site and the potential for hazardous winter driving conditions, emergency stores of non-perishable food and water will be kept on-site along with portable cots should it be necessary for personnel to remain on-site during such conditions.

18.5 Shootaring Canyon Mill Facilities

The existing Shootaring Canyon Mill facilities include the main mill building, shop and warehouse, office and security buildings, a non-potable water system for processing and fire suppression, a septic system, and the entire facility is fenced. The existing facilities are discussed in Section 17 and are shown on Figure 17.3.

Figure 18.1 - Velvet-Wood Existing Infrastructure



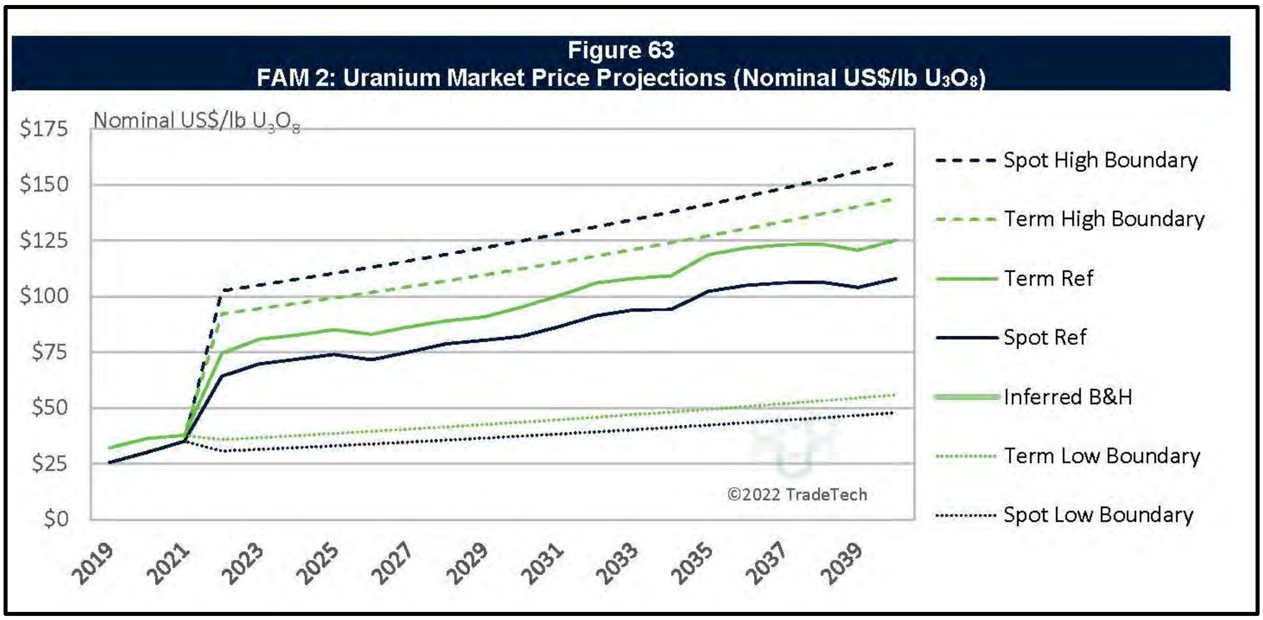
Section 19: Market Studies and Contracts

19.1 Uranium Price Forecast

Uranium does not trade on the open market, and many of the private sales contracts are not publicly disclosed since buyers and sellers negotiate contracts privately. Monthly long-term industry average uranium prices based on the month-end prices are published by Ux Consulting, LLC, and Trade Tech, LLC. Anfield has not begun any negotiations of any contracts to develop the property, including those associated with uranium sales, which is appropriate for a project at this level of development. The following table provides a Long-Term Uranium Price Forecasts from TradeTech LLC™ ("TradeTech™") 2022: Issue 3. The Forward Availability Model (FAM 2) forecasts how future uranium supply enters the market assuming restricted project development because of an unsupportive economic environment. Currently most US producers are in a mode of care and maintenance and numerous facilities globally are also slowing or shutting in production at least on a temporary basis. This condition aligns with the FAM 2 projections.

Term forecasts beginning 2025 or later and extending into the future are considered the most reasonable for purposes of this report, as they consider the effects of prices on future existing and new production. In addition, larger projects are typically supported by long-term contracts with investment-grade nuclear utilities. Therefore, term prices are most appropriate for purposes of this report.

Figure 19.1 - TradeTech Uranium Market Price Projections- FAM2 (Nominal US$)



From TradeTech™ 2022

The Term price projections for uranium oxide (USD) from TradeTech™ 2022, for 2023, FAM 2, Term Ref, exceed $75/lb. Projections of uranium price through 2040 increase from these values. The author recommends, as a conservative measure, the use of a long-term uranium price of $70.00

USD per pound uranium oxide for the consideration of reasonable prospects of economic extraction (Beahm, 2023).

19.2 Vanadium Price Forecast

Vanadium prices are more transparent than uranium prices. Vanadium pentoxide price ranged from \$6.70 to \$16.40 per pound in a five-year period from 2017 through 2021. The lowest price occurred in 2020 during the Covid pandemic and the highest price preceding the pandemic in 2019 (U.S. Geological Survey, Mineral Commodity Summaries, January, 2022).

As recently as August 9, 2022, Energy Fuels Inc. announced their Q2-2022 results which states; "*As a result of strengthening vanadium markets, during the six months ended June 30, 2022, the Company sold approximately 575,000 pounds of* V_2O_5 *at a gross weighted average price of \$13.44 per pound of* V_2O_5*.*"

Based on the foregoing, a price of \$12.00 per pound for vanadium pentoxide is recommended as the base case for this PEA.

By their nature, all commodity price assumptions are forward-looking. No forward-looking statement can be guaranteed, and actual future results may vary materially.

Section 20: Environmental Studies, Permitting, and Social or Community Impact

A range of different permits and licenses would be needed for the mining and various mineral processing options considered in this report. Similarly, a variety of additional environmental studies would be required. Agencies with jurisdiction include;

- Utah Department of Environmental Quality (UDEQ) Division of Radiation Control (DRC), source material licensing.
- Utah Department of Environmental Quality (UDEQ) Divisions of Air Quality (DAQ), Water Quality (WQD, mill and mines.
- Utah Department of Natural Resources (UDNR) Division of Oil Gas and Mining (DOGM), Velvet-Wood Mine and drilling permits.
- Utah State Engineers Office (SEO) water rights.
- SEO and UDNR tailings dam permit and monitor well permits.
- Bureau of Land Management (BLM) Plan of Operations and Notice of Intent, mining and drilling.
- Colorado Mined Land Reclamation Board (CMLRB) Slick Rock Mine and drilling permits.
- Source Materials License*; Colorado Department of Public Health and Environment (CDPHE), only if uranium is recovered onsite including water treatment.
- Local county permits mine and mill depending on project specifics.

Major actions needed include;

- Reactivation of the mill
    - The existing Source Material License, UT0900480, issued by UDEQ/DRC, requires an amendment to convert from the current care and maintenance status to operational status.
    - Current investigations include a study by PSE which will provide substantial designs for the rehabilitation of the mill and provide basis amending the mill license. and a reclamation design for the mill tailings by Engineering Analytics. These studies are scheduled to be completed by June and the fall 2023, respectively.
    - The mill is being maintained along with all additional permits and licenses and required environmental monitoring programs.
- Velvet-Wood Mine
    - The existing Large Mine Permit, UTU68060, issued by DOGM and the Plan of Operations issued by BLM require an amendment to convert from current care and maintenance status of operational status and to include the Wood portion of the mine.
    - The existing ground water discharge permit, UGW170003, issued by UDEQ/WQD will require amendment. If uranium is recovered from the ground water this would require licensing action by UDEQ/DRC.
- Slick Rock Mine
    - A new Large Mine Permit and Plan of Operations is required issued by CMLRB and BLM, respectively.

    - If it were necessary to recover uranium onsite from ground water treatment in order to meet discharge permit requirements, a source materials license from CDPHE would be required.
- Permits common to all operations.
    - Air quality permits.
    - Water quality permits, storm water discharge (construction and operations).
    - Monitor well permits.
    - Water rights for consumptive use.
    - Federal Mine Safety for mine and mill under the Mine Safety and Health Administration (MSHA).

20.1 Regulatory Status

The Shootaring Canyon Mill is located on private land. The Shootaring Canyon Mill is an existing facility which was constructed in 1980 and operated sporadically until 1982. The mill license has been maintained but will require a major amendment for operations. The tailings dam is in place, however individual lined tailings disposal cells would need to be permitted and constructed within the overall containment facility.

The Shootaring Canyon Mill has a Radioactive Materials License (RML; UT0900480) that is administrated by the UDEQ-DWMRC. This license currently authorizes possession of byproduct material (tailings and other milling wastes) and reclamation activities only. On June 29, 2016, Anfield submitted a renewal of the Radioactive Materials License to the UDEQ/DWMRC and a revised application in September 2018. The UDEQ/ DWMRC completeness review of the application indicated that there were two deficiencies, one related to the Reclamation and Decommissioning Plan and one related to the need for a mill refurbishment plan demonstrating use of best available technology. Anfield has initiated commissioning of these additional work products and expects them to be completed and submitted to UDEQ/DWMRC in the third quarter of 2023.

The Velvet-Wood mines are located on BLM lands. The Velvet mine was operated and has an existing Permit to Mine (Large Mine Permit No. M/037/040). Moving forward the mine permit will need to include the Wood mine and updating of the Velvet mine plan under the existing Velvet Mine permit. This will require an updated BLM Plan of Operations (PoO), a new Reclamation Plan and a new reclamation surety basis of estimate and bond. However, the mine portal could be opened, underground workings inspected, and the underground mine workings rehabilitation initiated, and large scale, bulk sampling of the mineralized material could be performed under the permit. Discussions have been held with DOGM and BLM and additional NEPA studies for wildlife, vegetation, and archeology are being commissioned due to the age of the original base line studies. Velvet also has existing air quality and ground water and surface water discharge permits which will require updating and amendment. Wood will require air quality and ground water and surface water discharge permits either separately or as amendments to the Velvet mine permit.

The Slick Rock mine has no current permits. Commercial uranium mining at Slick Rock occurred from 1955 through 1983; however, mining has a longer history with radium mining reported from the early 1900s through 1923, and vanadium mining beginning in 1931.

The Slick Rock Project is situated entirely on federal land and minerals administered by the Bureau of Land Management (BLM). Permitting will require a Large Mine Permit and Plan of Operations from CMLRB and BLM, respectively. These permits will require complete NEPA studies. However, there are private land holdings, the DOE Legacy site, and DOE uranium reserves in the vicinity. It is important to note that the DOE Legacy site, which is the permanent repository of the former Slick Rock mill tailings, is within the project area. The Slick Rock tailings were relocated from their original site near the Dolores River to the Legacy site. This site was selected based on US NRC criteria for the long-term disposal and isolation of uranium mill tailings including the completion of an EIS. The site is also subject to ongoing monitoring. The environmental data and assessments from the legacy site are of public record and can be used for reference. A summary of the regulatory status and required permits follows in Table 20-1.

20.2 Social and Community Impact

The Shootaring Canyon Mill is isolated in the far eastern portion of Garfield County, Utah. There would be essentially no viewshed impacts to the community from the different processing options and, as described in Section 20.2.3, the net socioeconomic impacts would be positive through increased employment and tax revenue with minimal long-term adverse impact on local civil infrastructure, housing, and services. Despite expected local support there is a risk of opposition from various Non-Government Organizations (NGOs)

The Velvet-Wood and Slick Rock mines are brownfield sites within the Colorado Plateau which has a long history of uranium and vanadium mining. The surrounding communities have a long history of working with and for the region's mining and mineral resource industry, and their support for this project has been strong. Despite expected local support, recent mineral development in the area has received opposition from various Non-Government Organizations (NGOs) and this should be anticipated for the Velvet-Wood and Slick Rock mines.

No potential social or community related requirements, negotiations, and/or agreements are known to the authors with respect to local communities and/or agencies. No outstanding environmental liabilities to Anfield are known to the authors.

According to the Fraser Institute Annual Survey of Mining companies, 2021, Utah ranks seventh of eighty-seven ranked jurisdictions with respect to the policy perception index. Within the US Utah ranks slightly behind Nevada in the policy perception index. Colorado is ranked thirty-third out of eighty-seven jurisdictions. The Policy Perception Index provides a comprehensive assessment of the attractiveness of mining policies in a jurisdiction and can serve as a report card to governments on how attractive their policies are from the point of view of an exploration manager (Fraser Institute, 2021).

Table 20.1 - Summary of Regulatory Status for Required Permits and Licenses

Permits/Licenses	Lead Agency/Cooperating Agency	Purpose	Status
Shootaring Canyon Mill			
Radioactive Material License	UDEQ-DWMRC	License to possess and process uranium ores and associated wastes	In timely renewal, partial submittal, submittal completion in process
Bond	UDEQ-DWMRC	Reclamation Surety	In place for current facility reclamation, updated bond required for return to operational status
Dam Permit	UDNR-DWR/SEO	Tailings Impoundment Embankment permit	In place, updated submittal pending approval of Radioactive Materials License
Air Authorization Order (minor source)	UDEQ-AQD	Air quality	In process
Groundwater Discharge Permit	UDEQ-WQD	Groundwater protection from water treatment	In timely renewal, approval pending
State Well Permits	UDEQ-DWMRC/SEO	Permitting groundwater wells for mill process water supply and environmental monitoring	Water supply wells in place and permitted. New wells proposed for new tailings impoundment, permitting of new wells pending DWMRC approval of Groundwater Discharge Permit renewal application
Water Rights	UDEQ-DWMRC/SEO	Mill processing water supply	Transfer from previous owner in process.
Velvet-Wood Mine			
Large Mine Permit	UDNR-DOGM/BLM	Mining permit	Existing, Update in Progress
UPDES Permit	UDNR-DOGM	Discharge of treated mine water	Approved in 2008, expired, renewal in progress
Groundwater Discharge Permit	UDNR-DOGM/UDEQ-WQD	Groundwater protection from water treatment	Approved in 2008, expired, renewal in progress
Air Authorization Order (minor source)	UDNR-DOGM/UDEQ-AQD	Air quality	Approved in 2008, expired, renewal in progress
County Septic System	San Juan County	Mine surface operations septic system	Pending application
Source Material License	UDEQ-DWMRC/UDNR-DOGM/BLM	Management or radioactive solid material generated from mine water treatment	Pending application
State Well Permits	UDNR-DOGM/SEO	Permitting groundwater wells for environmental monitoring	Complete
Water Rights	UDEQ-DWMRC/SEO	Mill processing water supply	Transfer from previous owner in process.

Slick Rock Mine			
Large Mine Permit	CDRMS/BLM	Mining permit	Pending application
Stormwater Discharge Permit	CDHPE	Discharge of treated mine water	Pending application
Groundwater Discharge Permit	CDHPE	Groundwater protection from water treatment	Pending application
Air Permit (minor source)	CDHPE	Air quality	Pending application
County Septic System	San Miguel County	Mine Surface Ops Septic system	Pending application
Source Material License	CDHPE	Management or radioactive solid material generated from mine water treatment	Pending application
State Well Permits	CDWR	Permitting groundwater wells for environmental monitoring	Pending application
Water Rights	CDWR	Mill processing water supply	Transfer from previous owner in process.

Table 20.2 - Summary of Environmental Data and Studies

Environmental Data/Studies	Lead Agency/Cooperating Agency	Status
Shootaring Canyon Mill		
Geology and Soil	UDEQ-DWMRC	Complete
Groundwater	UDEQ-DWMRC-WQD	Complete
Surface Water	UDEQ-DWMRC-WQD	Complete
Ecological Resources	UDEQ-DWMRC	Complete
Air Quality and Meteorology	UDEQ-DWMRC-AQD	Update in progress
Cultural Resources	UDEQ-DWMRC-SHPO	Complete
Velvet Wood Mine		
Geology and Soil	DOGM/BLM	Complete/Historical Data
Groundwater	DOGM/BLM	Update study in progress
Surface Water	DOGM/BLM	Update study in progress
Ecological Resources	DOGM/BLM	Update study in progress
Air Quality and Meteorology	DOGM/BLM	Update study in progress
Cultural Resources	DOGM/BLM	Update study in progress
Slick Rock Mine		
Geology and Soil	CDRMS /BLM	Complete/Historical Data
Groundwater	CDRMS /BLM	New study required
Surface Water	CDRMS /BLM	New study required
Ecological Resources	CDRMS /BLM	New study required
Air Quality and Meteorology	CDRMS /BLM	New study required
Cultural Resources	CDRMS /BLM	New study required

Section 21: Capital and Operating Costs

Project cost estimates are based on a conventional random room and pillar underground mine operation at the Velvet and Wood and Slick Rock mine areas. Mined material would be hauled by truck to the Shootaring Canyon Mill approximately 180 miles from Velvet and 200 miles from Slick Rock. The mill would be fully refurbished and would process mined material for both uranium and vanadium recovery.

All costs are estimated in constant 2022 US Dollars. Operating (OPEX) and Capital (CAPEX) costs reflect a full and complete operating cost going forward including all pre-production costs, permitting costs, mine costs, and complete reclamation and closure costs for of the mine and mineral processing facility. CAPEX does not include sunk costs or acquisition costs.

A current investigation and design study for the reactivation of the Shootaring Canyon Mill has been commissioned by Anfield who has engaged the firm of Precision System Engineering (PSE) of Salt Lake City, Utah for this study. The PSE study will provide substantial designs for the rehabilitation of the mill, will provide a basis updating the mill license, and will consider options for increasing the mill throughput. The initial study is scheduled to be completed by June 2023, while a report outlining advanced engineering and design is expected to be completed in fall 2023. Mine design and permitting for the Velvet Wood and Slick Rock mines are also ongoing. It is recommended that this PEA be revised following completion of these investigations and studies.

Mining and mineral recovery methods are described in Sections 16 and 17, respectively.

A summary of key assumptions follows:

- CAPEX Estimates
  - Underground Equipment based on InfoMine Mining Cost Service data and/or recent vendor quotes with 15% added contingency.
  - Pre-Production Expenditures based on InfoMine cost data and/or direct calculations with 25% contingency added.
  - Surface Facilities based on InfoMine cost data and/or recent vendor quotes with 25% added contingency.
  - Refurbishment of the Shootaring Canyon Mill to recover both uranium and vanadium, based on a current and updated evaluation of the Lyntek, 2008 study by the author Dr. Terry McNulty. The current mill CAPEX estimate includes a 15% contingency.
- OPEX Estimates
  - Underground Mine operating costs were based on continual operations of two 10 hour shifts per production day; productivity was based on 330 days per year or 90% utilization; cycle times were based on a 50-minute hour (83% reduction) to account for inefficiencies related to availability and utilization.
  - Salary and labor rates for mine workers were taken from Bureau of Labor Statistics data published by the states of Utah and Colorado, though 2021.
  - Transportation of mined product to the Shootaring Canyon Mill was based costs annual analyses published by the American Transportation Research Institute

(ATRI) and the Energy Information Administration (EIA). No contingency was added but the higher of the range of cost per ton mile estimates was used.

- Salaried and hourly personnel requirements for mineral processing were tabulated and fully burdened payrolls were derived from the annually updated InfoMine Mining Cost Service.
- Consumptions of sulfuric acid and sodium chlorate were derived from test work performed for Uranium One by Hazen Research. Usages of other chemicals such as Alamine 336, isodecanol, and soda ash were based on industry averages. Prices for most chemicals were obtained from Ryan Johnson, Western Region Sales Manager for Univar in Salt Lake City. The prices include delivery from plant or distribution point to Ticaboo.
- Estimates for maintenance and repair parts and supplies and for laboratory reagents and supplies were based on experience with similar projects.

Estimated Capital Expenditures (CAPEX) are summarized on Tables 21.1. CAPEX estimates include:

- Pre-production expenses related to engineering design, metallurgical testing, and permitting.
- Mine facilities and equipment.
- Direct processing plant refurbishing costs.
- Tailings related costs.

Estimated Operating Expenditures (OPEX) are summarized on Tables 21.2. OPEX estimates include:

- Direct mining costs.
- Haulage and handling costs related to the delivery of mined and stockpiled material to the Shootaring Canyon Mill.
- Direct mineral processing costs.
- Reclamation and bonding costs.
- Royalties and taxes.

Table 21.3 compares the OPEX and CAPEX cost per ton to the gross value of the recovered uranium and vanadium.

Table 21.1 - Capital Expenditure Summary

Capital Expenditures: $ x 1,000	**Year -1**	**Year 0**	**Year 1**
Permitting and Licensing Mill	$2,000	$1,500	
Permitting and Licensing Mines	$750	$500	
Mine CAPEX (Velvet-Wood and Slick Rock)			
Engineering and Design	$1,250	$1,000	
Mine Facilities	$2,500	$2,500	
Pre-Development	$2,600	$2,600	
Mine Equipment	$15,150	$15,150	
Shootaring Mill CAPEX			
New Plant within facility		$31,400	
Vanadium circuit		$13,400	
Tailings		$20,000	
Working Capital	One Time		$6,000
Replacement Mine Equipment @5%	Annual		$545
Replacement Plant Equipment	Annual		$460
TOTAL CAPITAL EXPENDITURES	**$24,250**	**$88,050**	**$6,000**
INITIAL CAPITAL (Years -1 and -2)		**$112,300**	

Table 21.2 - Operating Expenditure Summary

Direct Mine Costs:		
UG Mining Velvet-Wood	Per Ton Mined Material + Waste	$ 63.00
UG Mining Slick Rock	Per Ton Mined Material + Waste	$ 67.00
Handling Stockpile at Plant	Per Ton	$ 2.00
Weighted Average Direct Mine Cost Per Ton:	Per Ton to Mill (Rounded)	$ 104.00
Haulage/Handling Costs		per ton
Velvet-Wood	360 Miles @$2.30/mile	$ 20.70
Slick Rock	400 Miles @ $2,30/mile	$ 23.00
Weighted Average Haulage/Handling Costs:	Per Ton to Mill (Rounded)	$ 22.00
Mineral Processing Costs:		per ton
Includes Vanadium Circuit		$ 69.70
Weighted Average Direct Processing Costs:	Per Ton Processed (Rounded)	$ 70.00
Other Direct Costs:		
Reclamation Bond Mine (all mines)	$ 8,000.00	
Reclamation Mine		$ 8,000.00
Reclamation Tailings/Plant		$ 15,000.00
Reclamation Mill/Tailings: Current Bond is $12.3 Million - Use $15 Million	$ 15,000.00	$ 15,000.00
Annual Bond Cost (Mine/Plant))	2% annual rate	$ 340.00
Velvet Royalty (8% Utah, 1-2.5% private)	Use 5% average	5%
Slick Rock Royalty 4%		4%
Severance Tax	2.25%	2.60%
Shootaring Canyon Mill Property Tax	Use Mil Levy 0.01	$ 115.00
Weighted Average Other Direct Costs:		$ 50.00
Weighted Average ALL Direct Operating Costs	Per Ton Processed	$ 244.00

Table 21.3 - OPEX and CAPEX Summary

Weighted Average ALL Direct OPEX	Per Ton Processed	$ 244.00
CAPEX Cost Per Ton	Per Ton Processed	$ 46.00
Total Cost	Per Ton Processed	$ 290.00
Gross Value: Uranium ($70/lb) and Vanadium ($12/lb)	Per Ton Processed	$ 741.00

Section 22: Economic Analysis

22.1 Summary

For the purposes of this PEA, the Shootaring Canyon Mill would be refurbished to its original 750 tons per day capacity and a vanadium recovery circuit would be added. The PEA considers simultaneous mine feed from the Velvet-Wood decline and two production shafts at Slick Rock. Given the selective nature of the mining and the geometry of the mineralization, three production centers are needed to meet the mill tonnage capacity. Referring to the cash flow model Table 22.4 at the end of this section, the currently defined mineral resource at Velvet-Wood would be mined out in 8 years while production from the two shafts at Slick Rock would continue for 15 years. Thus, additional mill tonnage capacity would be available beginning in year 9. Additional mill feed could be sourced as captive feed from other Anfield mineral resource holdings in the Colorado Plateau or from mineral resource holdings of others under toll milling agreements.

The financial evaluations that follow represent constant 2022 US dollars. All costs are forward looking and do not include any previous project expenditures or sunk costs. Operating costs include all direct taxes and royalties and are presented for both pre- and post-State of Utah and US Federal Income Taxes. Estimation of US corporate income tax is complex as income tax relates to the overall income and expenses of the reporting entity, not a specific project. This analysis reflects the taxes that would be due if the project was stand-alone and subject to State of Utah, State of Colorado, and U.S. income tax. Due to the favorable regular tax depletion deduction, most mining companies' effective tax rate is the Alternative Minimum Tax (AMT) rate. The AMT rate is 20%. The mill is located in Utah which has a 5% corporate state income tax. Note the corporate tax rate in Colorado is slightly less than Utah at 4.4%.

Table 22.1 summarizes the estimated internal rate of return (IRR) and net present value (NPV) for the base case at a commodity price of $70/pound uranium oxide, a commodity price of $12/pound for vanadium oxide, and a discount rate of 8%.

Table 22.1 - Base Case Economic Criterion ($ x 1,000)

Pre-Income Tax		Post-Income Tax	
IRR 40%	NPV $238,398	IRR 33%	NPV $196,768

22.2 Breakeven Commodity Price

The base case commodity price for uranium and vanadium are $70/lb and $12/lb, respectively. Reducing these commodity prices by 40% to $42/lb and $7.20/lb, respectively, results in a breakeven condition.

22.3 Sensitivity Analysis

Tables 22.2 summarizes the Net Present Value (NPV) and Internal Rate of Return (IRR) before and after income tax over a range commodity prices and discount rates.

Table 22.2 - Sensitivity to Commodity Price and Discount Rate

Pre Income tax					Pre Income tax					Pre Income tax				
U Price	$70.00	NPV at 5% rate		$ 313,092	U Price	$63.00	NPV at 5% rate		$ 236,248	U Price	$ 77.00	NPV at 5% rate		$ 389,936
V Price	$12.00	NPV at 8% rate		$ 238,398	V Price	$10.80	NPV at 8% rate		$ 176,681	V Price	$ 13.20	NPV at 8% rate		$ 300,116
		NPV at 10% rate		$ 199,007	10% drop		NPV at 10% rate		$ 145,260	10% increase		NPV at 10% rate		$ 252,753
		NPV at 12% rate		$ 166,115			NPV at 12% rate		$ 119,038			NPV at 12% rate		$ 213,191
		IRR	**40%**				**IRR**	**33%**				**IRR**	**46%**	
Post Income tax					Post Income tax					Post Income tax				
U Price	$ 70.00	NPV at 5% rate		$ 263,824	U Price	$ 63.00	NPV at 5% rate		$ 198,720	U Price	$ 77.00	NPV at 5% rate		$ 328,928
V Price	$ 12.00	NPV at 8% rate		$ 196,768	V Price	$ 10.80	NPV at 8% rate		$ 144,389	V Price	$ 13.20	NPV at 8% rate		$ 249,147
		NPV at 10% rate		$ 161,440	10% drop		NPV at 10% rate		$ 115,772	10% increase		NPV at 10% rate		$ 207,108
		NPV at 12% rate		$ 131,980			NPV at 12% rate		$ 91,932			NPV at 12% rate		$ 172,027
		IRR	**33%**				**IRR**	**27%**				**IRR**	**38%**	

22.2 Sensitivity to Price

This project, like all similar projects, is quite sensitive to commodity prices as shown in Figure 22.1 and 22.2 for pre and post income tax NPV, respectively.

Figure 22.1 – NPV Price Pre-Tax Sensitivity Chart

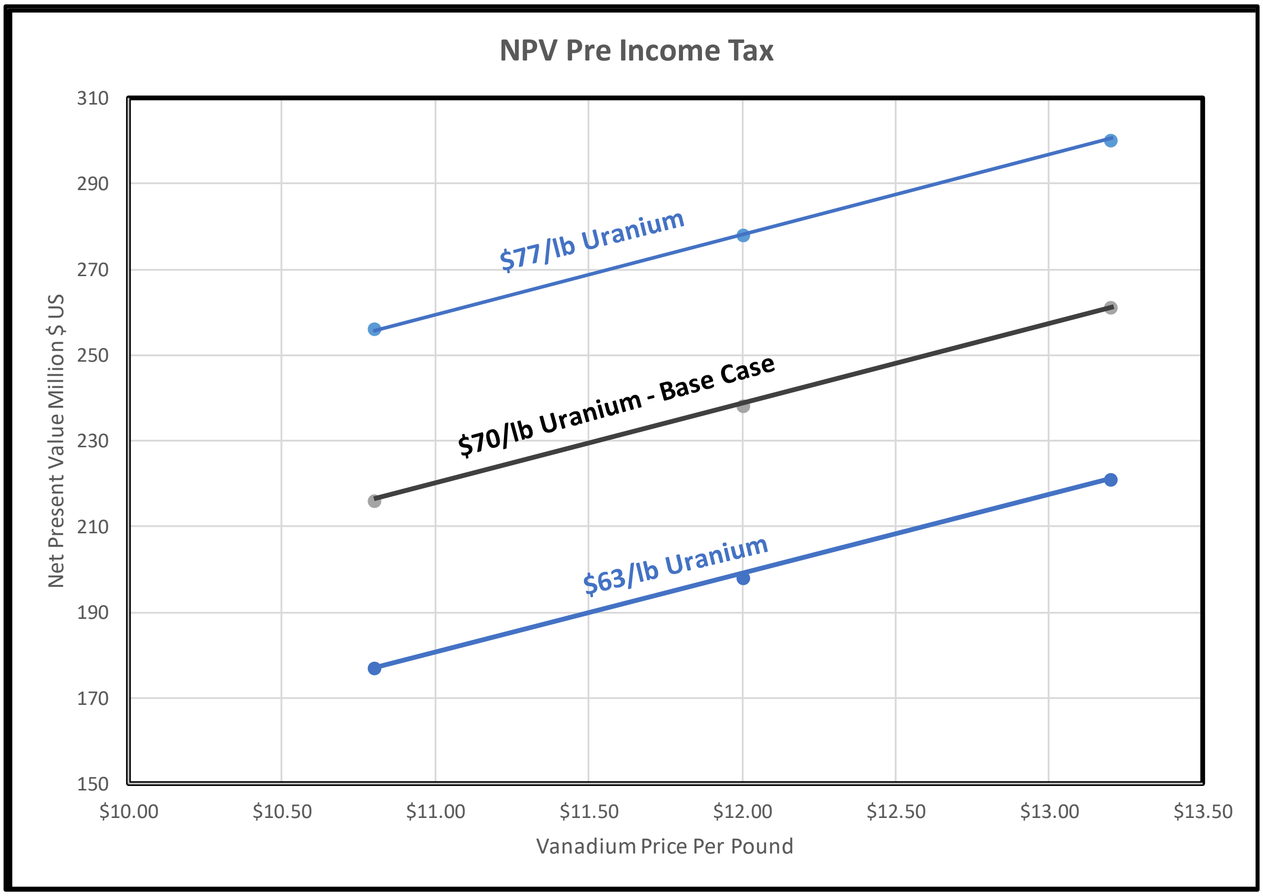
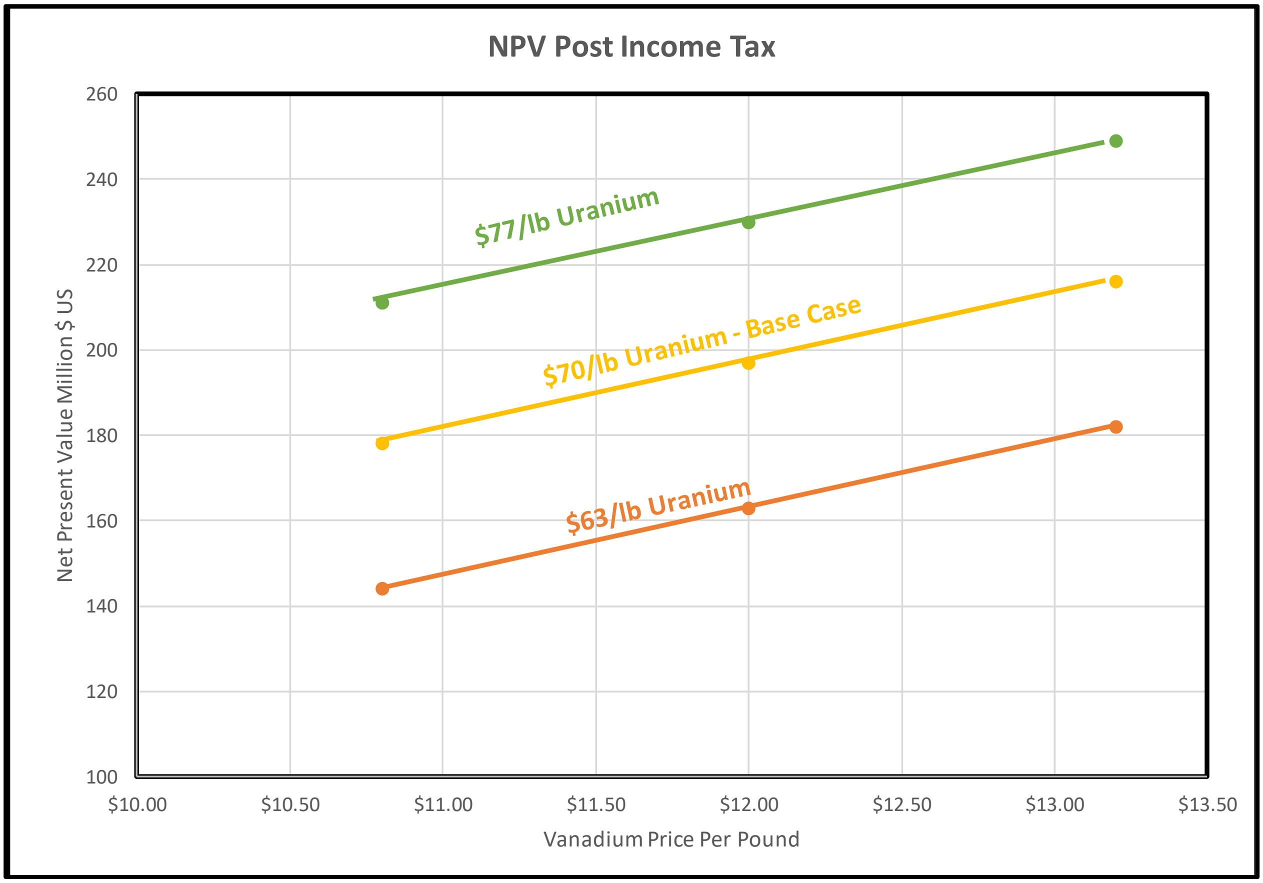


Figure 22.2 – NPV Price Post-Tax Sensitivity Chart



22.3 Sensitivity to Other Factors

Table 22.3 summarizes the % change in IRR and NPV based on a 10% variance in the base case relative to process recovery, mine dilution, CAPEX, and OPEX.

The factors to which the project has the greatest sensitivity are mined grade and process recovery. The project is much less sensitive to changes in CAPEX and OPEX.

Table 22.3 - Sensitivity to Other Factors

10 Percent Change	Change in IRR
Recovery (U & V)	7 Percent
Mine Dilution	1 Percent
CAPEX	3 Percent
OPEX	3 Percent

22.4 Alternative CAPEX and Recovery

A current investigation and design study for the reactivation of the Shootaring Canyon Mill has been commissioned by Anfield who has engaged the firm of Precision System Engineering (PSE) of Salt Lake City, Utah for this study. The PSE study will provide substantial designs for the rehabilitation of the mill, will provide a basis updating the mill license, and will consider options for increasing the mill throughput. The initial study is scheduled to be completed by June 2023, while a report outlining advanced engineering and design is expected to be completed in fall 2023.

The current mill refurbishment study is evaluating cost and benefit of various options with respect to mill equipment. Preliminary indications are that there will be a benefit in more complete replacement of equipment resulting in higher CAPEX than the base case provided herein.

With these additions, it is the authors' opinion, as expressed in Section 11, that is very likely that the Shootaring Canyon Mill will be able to achieve at least 96 percent U_3O_8 recovery, especially given the high average feed grades of 0.24 to 0.29% U_3O_8 and the high free acid concentration during leaching necessary for vanadium recovery. Also, the vanadium plant will have the advantage of state-of-art instrumentation and process control and may readily achieve 80% V_2O_5 recovery. For this alternative the internal rate of return would be essentially the same as the base case and the NPV, at an 8% discount rate, would increase approximately 8%.

22.5 Cash Flow Model

The case flow model for the base case is provided in Table 22.4 which follows.

Table 22.4 - Cash Flow

Conceptual Cash flow Shootering Mill and Slick Rock																						
Totals	**Totals**		**Year**	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	**TOTAL**
						Ticaboo Stockpile	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood	Velvet/Wood									
Tons Waste	273						43	55	51	45	45	18	16									273
Tons undilluted	757					76	39	65	74	119	132	148	104									757
Tons Product	795					80	41	68	77	125	139	156	109								-	795
Grade % U3O8	0.308					0.157	0.371	0.304	0.339	0.281	0.358	0.394	0.218									0.308
Pounds Contained U3O8	4,889					251	301	414	524	701	993	1,229	476								0	4,889
Grade V2O5	0.409					0.000	0.519	0.425	0.474	0.393	0.502	0.552	0.305									0.409
Pounds V2O5	6,493					0	421	580	733	981	1,391	1,720	667								0	6,493
						Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock A&B	Slickrock B	Slickrock B	Slickrock B	Slickrock B	Slickrock B		
Tons Waste	1,340					62	124	124	124	93	77	93	93	124	116	70	70	70	70	31		1,340
Tons undilluted	1,584					75	150	150	150	113	94	113	113	150	140	75	75	75	75	34		1,584
Tons Product	1,663					79	158	158	158	118	99	118	118	158	147	79	79	79	79	36		1,663
Grade % U3O8	0.22					0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.223	0.221	0.200	0.200	0.200	0.200	0.200		0.218
Pounds Contained U3O8	7,256					352	705	705	705	529	440	529	529	705	651	316	316	316	316	142		7,256
Grade V2O5	1.31					1.339	1.339	1.339	1.339	1.339	1.339	1.339	1.339	1.339	1.329	1.202	1.202	1.202	1.202	1.202		1.309
Pounds V2O5	43,533					2,114	4,228	4,228	4,228	3,171	2,643	3,171	3,171	4,228	3,908	1,897	1,897	1,897	1,897	854		43,533
Tons Total	2,456					159	198	226	235	243	237	272	228	158	147	79	79	79	79	36		2,456
Plant feed, % U3O8	0.247					0.190	0.253	0.247	0.261	0.253	0.302	0.323	0.220	0.223	0.221	0.200	0.200	0.200	0.200	0.200		0.247
Pounds contained U3O8	12,144					603	1,006	1,119	1,228	1,229	1,434	1,757	1,005	705	651	316	316	316	316	142		12,144
Pounds recovered U3O8	11,173					555	925	1,029	1,130	1,131	1,319	1,617	924	648	599	291	291	291	291	131		11,173
Recovery % U3O8	92%					92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%	92.00%		
U3O8 price/pound	$ 70.00					$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00	$ 70.00		
U3O8 revenue	$ 782,086					$ 38,855	$ 64,756	$ 72,059	$ 79,101	$ 79,162	$ 92,337	$ 113,161	$ 64,703	$ 45,382	$ 41,942	$ 20,366	$ 20,366	$ 20,366	$ 20,366	$ 9,165		782,086
Pounds Contained V2O5	50,026					2,114	4,649	4,808	4,961	4,152	4,033	4,891	3,838	4,228	3,908	1,897	1,897	1,897	1,897	854		50,026
Grade % V2O5	1.02																					1.019
Pounds Recoverd V2O5	37,520					1,586	3,487	3,606	3,721	3,114	3,025	3,668	2,878	3,171	2,931	1,423	1,423	1,423	1,423	640		37,520
Recovery V2O5	75%					75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%		
V2O5 price per pound	$ 12.00					$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00		
V205 revenue	$ 450,235					$ 19,026	$ 41,843	$ 43,272	$ 44,650	$ 37,368	$ 36,300	$ 44,021	$ 34,540	$ 38,053	$ 35,169	$ 17,077	$ 17,077	$ 17,077	$ 17,077	$ 7,685		450,235
GROSS REVENUES						$ 57,882	$ 106,599	$ 115,331	$ 123,751	$ 116,530	$ 128,637	$ 157,182	$ 99,243	$ 83,434	$ 77,110	$ 37,443	$ 37,443	$ 37,443	$ 37,443	$ 16,849	$ -	$ 1,232,321
Direct Mine Costs:																						
UG Mining Velvet	Per ton Muck	$ 63.00					5,138	7,566	7,853	10,335	11,155	10,454	7,567	0	0	0	0	0	0	0	0	60,070
UG Mining Slick Rock	Per ton Muck	$ 67.00				9,182	18,364	18,364	18,364	13,773	11,478	13,773	13,773	18,364	17,176	9,721	9,721	9,721	9,721	4,375	0	195,874
Handling Stockpile at Mill	Per Ton Feed	$ 2.00				160																160
Subtotal Direct Mine Costs:			$ -			$ 9,342	$ 23,503	$ 25,930	$ 26,218	$ 24,109	$ 22,633	$ 24,228	$ 21,340	$ 18,364	$ 17,176	$ 9,721	$ 9,721	$ 9,721	$ 9,721	$ 4,375	$ -	256,103
Haulage/Handling Costs		per ton																				
Slick Rock (RT Mileage)	.30/m, 40tons	$ 23.00				1,816	3,632	3,632	3,632	2,724	2,270	2,724	2,724	3,632	3,382	1,816	1,816	1,816	1,816	817	0	38,251
Velvet/Wood (RT Mileage)	.30/m, 40tons	$ 20.70					840	1,411	1,601	2,582	2,870	3,225	2,266	0	0	0	0	0	0	0		
Subtotal Haulage/Handling Costs:		$ 21.60				$ 1,816	$ 4,472	$ 5,043	$ 5,233	$ 5,306	$ 5,140	$ 5,949	$ 4,990	$ 3,632	$ 3,382	$ 1,816	$ 1,816	$ 1,816	$ 1,816	$ 817	$ -	$ 53,046
Mineral Processing Costs:		per ton																				
		$ 69.70				11,066	13,835	15,757	16,397	16,950	16,542	18,975	15,885	11,007	10,250	5,504	5,504	5,504	5,504	2,477	0	171,155
Subtotal Direct Processing Costs:		$ 69.70	$ 15.32			$ 11,066	$ 13,835	$ 15,757	$ 16,397	$ 16,950	$ 16,542	$ 18,975	$ 15,885	$ 11,007	$ 10,250	$ 5,504	$ 5,504	$ 5,504	$ 5,504	$ 2,477	$ -	$ 171,155
Other Direct Costs:		Slick rock	Velvet/Wood																			
Reclamation Mine		$ 6,000.00	$ 2,000.00																		8,000	8,000
Reclamation Mill/Tailings	Use $15mm	$ 15,000.00																			15,000	15,000
Annual Bond Cost (Mill/Tailing	% annual rate	$ 460.00				460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	7,360
Velvet (8% Utah 1 - 2.5 priva	e 5% average	5%				808	1,158	1,595	2,016	2,698	3,825	4,730	1,833	0	0	0	0	0	0	0		18,663
Slick rock U	vary USE 4%	4%				908	1,815	1,815	1,815	1,361	1,135	1,361	1,361	1,815	1,678	815	815	815	815	367	0	18,690
Slick rock V	vary USE 4%	4%				761	1,522	1,522	1,522	1,142	951	1,142	1,142	1,522	1,407	683	683	683	683	307	0	15,672
Severance Tax CO 2.25% UT 2.6%	Use 2.6%	2.60%	On Gross			1,505	2,772	2,999	3,218	3,030	3,345	4,087	2,580	2,169	2,005	974	974	974	974	438	0	32,040
Property Tax Utah	Mill Levy 0.01	$ 115.00	per year			115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	1,840
Subtotal Other Costs:		$ 47.75	$ 10.50			$ 4,557	$ 7,842	$ 8,506	$ 9,146	$ 8,806	$ 9,830	$ 11,895	$ 7,492	$ 6,082	$ 5,664	$ 3,046	$ 3,046	$ 3,046	$ 3,046	$ 1,687	$ 23,575	$ 117,266
TOTAL ALL Direct Costs						$ 26,780	$ 49,652	$ 55,236	$ 56,994	$ 55,170	$ 54,145	$ 61,047	$ 49,708	$ 39,085	$ 36,473	$ 20,087	$ 20,087	$ 20,087	$ 20,087	$ 9,355	$ 23,575	$ 597,570
Cash Flow Pre-tax						$ 31,101	$ 56,947	$ 60,095	$ 66,756	$ 61,360	$ 74,492	$ 96,135	$ 49,535	$ 44,349	$ 40,637	$ 17,356	$ 17,356	$ 17,356	$ 17,356	$ 7,494	$ (23,575)	$ 634,751
Capital Expenditures:																						
Permitting and Licensing																						
Mill	over 2 years			2,000	1,500																	
Mine (3 facilities Vevlet & 2 West Sl	over 2 years			750	500																	
Mine (3 facilities Vevlet & 2 West Slope)																						
Engineering and Design	$1,000 each			1,250	1,000																	
Mine Facilites	$2,500 x2			2,500	2,500																	
Pre-Devlopment (VW, SR)	700, 4,500			2,600	2,600											500						
Mine Equipment (VW, SR)	$11,100, 19,200			15,150	15,150																	
Refurbish Ticaboo Mill																						
Mill CAPEX	$ 31,400				$ 31,400																	
Vanadium circuit	$ 13,400				$ 13,400																	
Tailings	$ 20,000				$ 20,000																	
Working Capital	3 months OPEX					$ 6,000																$ (6,000)
Replacement Mine Equipment @5%							$ 758	$ 758	$ 758	$ 758	$ 758	$ 758	$ 758	$ 758	$ 758							
Replacement Plant Eqipment							$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000					
TOTAL CAPITAL EXPENDITURES				$ 24,250	$ 88,050	$ 6,000	$ 1,758	$ 1,758	$ 1,758	$ 1,758	$ 1,758	$ 1,758	$ 1,758	$ 1,758	$ 1,758	$ 1,500	$ 1,000	$ -	$ -		$ -	$ (6,000)
NET CASH FLOW				$ (24,250)	$ (88,050)	$ 25,101	$ 55,190	$ 58,338	$ 64,999	$ 59,602	$ 72,735	$ 94,378	$ 47,778	$ 42,591	$ 38,880	$ 15,856	$ 16,356	$ 17,356	$ 17,356	$ 7,494	$ (23,575)	$ 498,133
CUMULATIVE NET CASH FLOW:				$ (24,250)	$ (112,300)	$ (87,199)	$ (32,009)	$ 26,329	$ 91,328	$ 150,930	$ 223,665	$ 318,042	$ 365,820	$ 408,411	$ 447,291	$ 463,147	$ 479,503	$ 496,859	$ 514,215	$ 521,708	$498,133	

Section 23: Adjacent Properties

Significant mine developments within and near the Lisbon Valley in which neither the authors nor Anfield have any material interest include:

- The Energy Fuels White Mesa Uranium Mill located in Blanding, Utah approximately 40 miles from the Velvet-Wood Project.
- The Lisbon Valley Copper Mine and heap leach facility is located approximately 3 miles north of the Velvet-Wood Project.
- The Energy Fuels Tony M mine is located approximately 2 miles north of the Shootaring Canyon Mill.

Significant mine development and recovery of uranium and vanadium products has occurred in the Uravan Mineral Belt. The mining history dates from the early 1900s for vanadium and to the 1940s for uranium.

Section 24: Other Relevant Data and Information

The authors are not aware of any other relevant data or information that would materially change the overall conclusions of this report.

Section 25: Interpretations and Conclusions

This report summarizes mineral resources for the Velvet-Wood and Slick Rock mines with mineral processing at common facility, the Shootaring Canyon Mill. The total estimated uranium mineral resources are summarized in Table 14.1. The associated vanadium mineral resource which will be mined as a co-product are summarized in Table 14.2. In addition to these in situ mineral resources, Anfield controls mineralized stockpiles at the Shootaring Mill and in the Lisbon Valley near the Velvet-Wood mines, as described in Section 16.1.

This is a restricted disclosure as allowed under section 2.3(3) of NI 43-101 which includes a Preliminary Economic Assessment (PEA) and is preliminary in nature such that it includes a portion of the inferred mineral resources as reported in Section 14 of the report. Mineral resources are not mineral reserves and do not have demonstrated economic viability in accordance with CIM standards. Inferred mineral resources are too speculative to have the economic considerations applied to them that would enable them to be categorized as mineral reserves, and there is no certainty that the outcomes estimated in the PEA will be realized. Mineral reserves are not estimated herein.

The Velvet-Wood Project is located in the Lisbon Valley Uranium District which historically was the largest uranium producing area in Utah. Portions of the project have been mined successfully in the past by conventional underground methods. The current mineral resource estimate is based on development of the resource in a similar manner. Uranium mineralization is found in the Cutler Formation near the unconformable contact with the Mossback Formation.

The Slick Rock Project is located in San Miguel County, Southwest Colorado, approximately 23.9 miles north of the town of Dove Creek. Surficial to shallow uranium/vanadium mineralization has been known in the Slick Rock area since the early 1900s (then called the McIntyre district) and was successfully mined through the early 1980s using conventional underground methods. Uranium/vanadium mineralization is hosted by the Upper Jurassic Morrison Formation and is typical of Colorado Plateau-style uranium/vanadium deposits.

Both projects contain mineralization which are strata bound and tabular based on available data and descriptions of each deposit in the literature. Both deposits contain uranium and vanadium. Both uranium and vanadium were recovered as co-products during past production.

25.1 Economic Analysis

Project cost estimates are based on a conventional random room and pillar underground mine operation at the Velvet-Wood and Slick Rock mine areas. Mined material would be hauled by truck to the Shootaring Canyon Mill approximately 180 miles from Velvet and 200 miles from Slick Rock. The mill would be fully refurbished and would process mined material for both uranium and vanadium recovery.

For the purposes of this PEA, the Shootaring Canyon Mill would be refurbished to its original 750 tons per day capacity and a vanadium recovery circuit would be added. The PEA considers simultaneous mine feed from the Velvet-Wood decline and two production shafts at Slick Rock. Given the selective nature of the mining and the geometry of the mineralization, three production centers are needed to meet the mill tonnage capacity. The currently defined mineral resource at Velvet-Wood would be mined out in 8 years while production from the two shafts at Slick Rock would continue for 15 years. Thus, additional mill tonnage capacity would be available beginning in year 9. Additional mill feed could be sourced as captive feed from other Anfield mineral resource holdings or from mineral resource holdings of others under toll milling agreements.

The base case is based on commodity prices of $70 per pound for uranium oxide and $12 per pound for vanadium pentoxide with mill recoveries of 92% and 75%, respectively. The base case economic evaluation shows:

- Pre-tax IRR 40%
- Post-tax IRR 33%
- Pre-Tax NPV (8% discount rate) $238,398 $US x 1,000
- Post-Tax NPV (8% discount rate) $196,768 $US x 1,000

Breakeven with respect to commodity price occurs when the base case commodity prices are reduced by 40% to $42/lb and $7.20/lb, respectively.

A current investigation and design study for the reactivation of the Shootaring Canyon Mill has been commissioned by Anfield who has engaged the firm of Precision System Engineering (PSE) of Salt Lake City, Utah for this study. The current mill refurbishment study is evaluating cost and benefit of various options with respect to mill equipment. Preliminary indications are that there will be a benefit in more complete replacement of equipment resulting in higher CAPEX than the base case resulting in higher recoveries of uranium and vanadium. This alternative, as discussed in Section 22, shows the internal rate of return would be essentially the same and the NPV, at an 8% discount rate, would increase approximately 8%.

25.2 Summary of Risks

It is the authors’ opinion that the technical risks associated are low for the following reasons:

- Portions of deposit have been successfully mined in the past.
- Uranium has been successfully extracted from mined material via conventional milling.
- The Project has some of the required operating permits and facilities in place.

The Project does have some risks similar in nature to other mining projects in general and uranium mining projects specially, i.e., risks common to mining projects including:

- Future commodity demand and pricing.
- Environmental and political acceptance of the project.
- Variance in capital and operating costs.
- Mine and mineral processing recovery and dilution.
- Continuity of mineralization with respect to thickness and grade may vary.
- Mining claims are subject to the Mining Law of 1872. Changes in the mining law could affect the mineral tenure.
- There is a risk that underground conditions at the Velvet Mine and/or the Slick Rock Mine may limit access to mineral resources.

The authors are not aware of environmental, permitting, legal, title, taxation, socio-economic, marketing, political, or other relevant factors which would materially affect the mineral resource estimates, provided the conditions of all mineral leases and options, and relevant operating permits and licenses are met.

Permitting and Licensing Risks:

- The BLM could require updated baseline environmental studies and initiate the National Environmental Policy Act (NEPA) process if the updated mine plan deviates significantly from the scope of the currently approved but outdated plan. This could have substantial cost and schedule impacts, as discussed in Section 20.
- The Colorado Department of Health and/or Utah Department of Environmental Quality - Division of Waste Management and Radiation Control could require a Source Materials License if mine dewatering treatment wastes exceed the minimum quantities identified in 10 CFR §40.22 (more than 150 lbs of material with greater than 0.05% natural uranium), which would incur risks of additional costs and extended schedule.

There are risks associated with any such permitting actions which could affect project schedule and costs. The Velvet-Wood and Slick Rock mines are brownfield sites within the Colorado Plateau which has a long history of uranium and vanadium mining. The mill is an existing facility. The surrounding communities have a long history of working with and for the region's mining and mineral resource industry, and their support for this project has been strong. Despite expected local support, recent mineral development in the area has received opposition from various Non-Government Organizations (NGOs) and this should be anticipated for the Velvet-Wood and Slick Rock mines.

Section 26: Recommendations

The following recommendations relate to potential improvement and/or advancement of the Project and fall within two categories; recommendations to potentially enhance the resource base and recommendations to advance the Project towards development. Both may be conducted contemporaneously.

All areas of Inferred Resource will require exploration to delineate the potential resource and upgrade the estimated quantities in those areas.

26.1 Phase 1

The Slick Rock project will require a Phase 1verification drilling program to confirm the existing database and upgrade the resource category. This would be followed by Phase 2 work, including delineation drilling, updating resource model, and preparation of a PEA update or PFS.

The Velvet mine does not require an initial phase of verification and would be included along with Slick Rock in Phase 2.

Based on the successful completion of the Phase 1 verification drilling program as shown in Table 26.1 below and a decision to move the Slick Rock Project forward to production, Phase 2 would be recommended as discussed in Section 26.2. Only the Phase 1 verification drilling program is recommended currently for the Slick Rock Project

Table 26.1 - Slick Rock Phase 1: Verification Drilling Cost Estimate

Item	**Cost (USD)**
Permitting and Reclamation	$20,000
20 Conventional Mud Holes (1,200ft average 24,000 ft total)	$450,000
Site Supervision Including Geological Services	$40,000
Geophysical Logging 20 Holes	$30,000
Road Maintenance	$10,000
Total Phase 1 Cost Estimate	$550,000

26.2 Phase 2

The Velvet Mine Area and resources are well delineated in the west and fairly well delineated in the east. The eastern portion of the Velvet mine resource will need to be drilled from the underground workings during any future development to classify resources into the Measured and/or Reserve categories ahead of mining extraction operations. The Wood resource area is less well delineated and will require additional surface and/or underground drilling to better define and quantify the resource prior to development.

The Phase 2 recommendations and cost estimates for the Velvet-Wood Project are provided in Table 26.2. The Phase 2 recommendations and cost estimates for the Slick Rock Project are provided in Table 26.3. The total Phase 2 cost is estimated at $4.5 million USD.

Table 26.2 - Velvet-Wood Exploration Drilling Cost Estimate

Item	**Cost (USD)**
Permitting and reclamation	$150,000
10 Air Rotary Collars for DDC Tails (1,200 ft average, 12,000 ft total)	$180,000
10 Diamond Core Tails (400 ft average, 4,000 ft total)	$400,000
20 Conventional Mud Holes (1,500 ft average 60,000 ft total)	$600,000
Site Supervision Including Geological Services	$200,000
Geophysical Logging 50 Holes (1,500 ft average)	$120,000
Assay of Core and Drill Chips (2,000 samples by ICP-MS)	$200,000
Resource Model Update, Reporting and Preparation of PFS	$300,000
Road Maintenance	$50,000
Total	$2,200,000

Table 26.3 - Slick Rock Phase 2: Exploration Drilling Cost Estimate

Item	**Cost (USD)**
Permitting and Reclamation	$150,000
10 Air Rotary Collars for DDC Tails (800 ft average, 8,000 ft total)	$120,000
10 Diamond Core Tails (200 ft average, 2,000 ft total)	$200,000
40 Conventional Mud Holes (900 ft average 36,000 ft total)	$720,000
Site Supervision Including Geological Services	$200,000
Geophysical Logging 50 Holes (850 ft average)	$120,000
Assay of Core and Drill Chips (2,000 samples by ICP-MS)	$200,000
Metallurgical Heap Leach Testing	$240,000
Resource Model Update, Reporting and Preparation of PFS	$300,000
Road Maintenance	$50,000
Total	$2,300,000

Section 27: References

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Section 28: Signature Page and Certification of Qualified Person

SIGNATURE PAGE AND CERTIFICATE OF QUALIFIED PERSON

DOUGLAS L. BEAHM

I, Douglas L. Beahm, P.E., P.G., do hereby certify that:

1. I am the Principal Engineer and President of BRS, Inc., 1130 Major Avenue, Riverton, Wyoming 82501.
2. I am the principal author of "The Shootaring Canyon Mill and Velvet-Wood and Slick Rock Mines, Preliminary Economic Assessment, National Instrument 43-101", dated May 6, 2023 (the "Technical Report").
3. I graduated with a Bachelor of Science degree in Geological Engineering from the Colorado School of Mines in 1974. I am a licensed Professional Engineer in Wyoming, Colorado, Utah, and Oregon, a licensed Professional Geologist in Wyoming and a Registered Member of the Society for Mining, Metallurgy, and Exploration.
4. I have worked as an engineer and a geologist for over 49 years. My work experience includes uranium exploration, mineral resource estimation, reserves estimation, mine production, and mine/mill decommissioning and reclamation. Specifically, I have worked as an exploration geologist, chief geologist, chief mine engineer and consultant with numerous uranium projects hosted in sandstone environments in the Western US.
5. I have visited the site previously on many occasions during 2007 and 2008. I made recent site visits to Slick Rock on February 14, 2023, and the Shootaring Canyon mill on February 16, 2023. I attempted to visit Velvet-Wood on February 14, 2023 but winter conditions precluded access to the site.
6. I am responsible for all sections of the report of the Technical Report.
7. I am independent of the issuer in accordance with the application of Section 1.5 of NI 43-101. I have no financial interest in the property and am fully independent of Anfield. I hold no stock, options or have any other form of financial connection to Anfield, Anfield is but one of many clients for whom I consult.
8. I do have prior work experience on the project for a previous owner during 2007 and 2008 as discussed in the Technical Report.
9. I have read the definition of "qualified person" set out in National Instrument 43-101 and certify that by reason of my education, professional registration, and past relevant work experience, I fulfill the requirements to be a "qualified person" for the purposes of NI 43-101.
10. I have read NI 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with same.
11. As of the date of this report, to the best of my knowledge, information and belief, the parts of the Technical Report for which I am responsible contain all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.

May 6, 2023

"original signed and sealed"

/s/ Douglas L. Beahm

Douglas L. Beahm, SME Registered Member

SIGNATURE PAGE AND CERTIFICATE OF QUALIFIED PERSON

CARL DAVID WARREN

I, Carl David Warren, P.E., P.G., do hereby certify that:

1. I am a Project Engineer for BRS Engineering, located in Riverton Wyoming, at 1130 Major Ave.
2. I am a contributing author of "The Shootaring Canyon Mill and Velvet-Wood and Slick Rock Mines, Preliminary Economic Assessment, National Instrument 43-101", dated May 6, 2023 (the "Technical Report").
3. I graduated with a Bachelor of Science in Geological Engineering from the Colorado School of Mines in 2009 and have a Master of Science Degree in Nuclear Engineering from the Colorado School of Mines in 2013. I am Licensed Professional Engineer in the State of Wyoming.
4. I have worked as both an engineer and a geologist for a cumulative 14 years and have over 15 years of working experience in the mining industry. My relevant work experience includes underground mining, ore control, geological mapping, core logging and data management, uranium exploration, and uranium resource modelling.
5. I last visited the site on April 12 and 13, 2023.
6. I am independent of the issuer in accordance with the application of Section 1.5 of NI 43-101. I have no financial interest in the property and am fully independent of Anfield. I hold no stock, options or have any other form of financial connection to Anfield.
7. I am responsible for portions of Section 14 and 15 and contributed to all portions of the Technical Report.
8. I do not have prior working experience on the property.
9. I have read the definition of "qualified person" set out in National Instrument 43-101 and certify that by reason of my education, professional registration, and past relevant work experience, I fulfill the requirements to be a "qualified person" for the purposes of NI 43-101.
10. I have read NI 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with same.
11. As of the date of this report, to the best of my knowledge, information and belief, the parts of the Technical Report for which I am responsible contain all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
12. I consent to the filing of the Technical Report and the Annual Information Form referencing the Technical Report with any stock exchange and/or other appropriate regulatory authority.

May 6, 2023

"original signed and sealed"

/s/ Carl David Warren

Carl David Warren, SME Registered Member

SIGNATURE PAGE AND CERTIFICATE OF QUALIFIED PERSON

HAROLD J. HUTSON

I, Harold J. Hutson, P.E., P.G., do hereby certify that:

1. I am the Senior Engineer for BRS Engineering, located in Riverton Wyoming, at 1130 Major Ave.
2. I am a contributing author of "The Shootaring Canyon Mill and Velvet-Wood and Slick Rock Mines, Preliminary Economic Assessment, National Instrument 43-101", dated May 6, 2023 (the "Technical Report").
3. I graduated with a Bachelor of Science in Geological Engineering from the Colorado School of Mines in 1995. I am a Licensed Professional Engineer and Licensed Professional Geologist in the State of Wyoming.
4. I have worked as both an engineer and a geologist for 28 years. My relevant work experience includes mine and mine land reclamation design, minerals exploration, and mineral resource modelling. My work in mineral commodities has included uranium, gold, mineral sands, rare earths, and coal.
5. I last visited the site on April 12 and 13, 2023.
6. I am independent of the issuer in accordance with the application of Section 1.5 of NI 43-101. I have no financial interest in the property and am fully independent of Anfield. I hold no stock, options or have any other form of financial connection to Anfield.
7. I am responsible for peer review of the Technical Report.
8. I do have previous work experience on the property including preparation of the mine reclamation plan and assistance in the preparation of the large mine permit for Uranium One.
9. I have read the definition of "qualified person" set out in National Instrument 43-101 and certify that by reason of my education, professional registration, and past relevant work experience, I fulfill the requirements to be a "qualified person" for the purposes of NI 43-101.
10. I have read NI 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with same.
11. As of the date of this report, to the best of my knowledge, information and belief, the parts of the Technical Report for which I am responsible contain all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.
12. I consent to the filing of the Technical Report and the Annual Information Form referencing the Technical Report with any stock exchange and/or other appropriate regulatory authority.

May 6, 2023

"original signed and sealed"

/s/ Harold J. Hutson

Harold J. Hutson, SME Registered Member

SIGNATURE PAGE AND CERTIFICATE OF QUALIFIED PERSON

Terrence P. ("Terry") McNulty

I, Terrence P. ("Terry") McNulty, D. Sc., P.E., do hereby certify that:

1. I am the owner and President of T. P. McNulty and Associates, Inc., located at 4321 North Camino de Carrillo, Tucson, AZ, 85750-6375. My email address is tpmacon1@aol.com.
2. I am a co-author of "The Shootaring Canyon Mill and Velvet-Wood and Slick Rock Mines, Preliminary Economic Assessment, National Instrument 43-101", dated May 6, 2023 (the "Technical Report").
3. I obtained a Bachelor of Science degree in Chemical Engineering from Stanford University in 1961, a Master of Science degree in Metallurgical Engineering from Montana School of Mines in 1963, and a Doctor of Science degree from Colorado School of Mines in 1966. I am a Registered Professional Engineer in the State of Colorado (License # 24789) and a Registered Member (# 2,152,450RM) of the Society of Mining, Metallurgy, and Exploration, Inc.
4. I have worked as a metallurgical engineer for a total of 62 years, including years worked between degrees. My recent experience for the purpose of the Study is as follows:
    a. I have worked as a consultant on 35 uranium projects during the last 17 years and have contributed to NI 43-101 compliant studies for many of those.
    b. I was Manager of Corporate R&D and Technical Services for a large, diversified mining firm, The Anaconda Company, which was a major uranium producer.
5. I have visited the site previously (2007-2008) but did not make a current site visit, as disclosed in the report.
6. I am responsible for Sections 13 and 17 of the Technical Report.
7. I am independent of the issuer in accordance with the application of Section 1.5 of NI 43-101. I have no financial interest in the property and am fully independent of Anfield. I hold no stock, options, nor have any other form of financial connection to Anfield. Anfield is but one of many clients for whom I consult.
8. I have prior work experience on the project, being involved with an engineering study completed by a former owner of the project during 2007 and 2008.
9. I have read the definition of "qualified person" set out in National Instrument 43-101 and certify that, by reason of my education, professional registration, and past relevant work experience, I fulfill the requirements to be a "qualified person" for the purposes of NI 43-101.
10. I have read NI 43-101 and Form 43-101F1, and the Technical Report has been prepared in compliance with same.
11. As of the date of this report, to the best of my knowledge, available information, and belief, the parts of the Technical Report for which I am responsible contain all scientific and technical information that is required to be disclosed to make the Technical Report not misleading.

May 6, 2023

"original signed and sealed"
/s/ Terrence P. McNulty

Terrence P. McNulty, SME Registered Member

Exhibit 19

Received on 3/31/2025
Permit #M0370040
Task# T-23631

BRS, Inc. Engineering
1130 Major Ave.
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Phone: 307-857-3079 Fax: 307-857-3080

TO: Wayne Western (waynewestern@utah.gov)

CC: Joshua Bleak (josh.bleak@gmail.com) ,Corey Dias (cdias@anfieldresources.com) , John Howard Eckersley (johneckersley@hey.com), Doug Beahm (dbeahm@brsengineering.com), Tina A. Marian (tmarian@blm.gov), Tyler Wiseman (twiseman@utah.gov)

FROM: Carl Warren

DATE: March 31, 2025

RE: Initial Review of Revised Notice of Intention to Commence Large Mining Operations, Anfield Resources Holding Corporation, Velvet Mine, M/037/0040, Task #23218, San Juan County, Utah

Dear Mr. Western,

Thank you and your team for your feedback on the Velvet-Wood LMO. We have incorporated your comments into the text and figures of the Plan of Operations and its attachments. Please see the responses to individual comments below. We hope that you find this version to be more complete and await your further comments.

Please see the updated PoO and attachments via the following Google Drive Link:

One exception to our response is that work remains to be completed on the Reclamation Surety calculation within the DOGM formatting. We are investigating the use of your new SRCE calculator. Thank you for your provided data sheets; both for the items we requested as well as the SRCE data sheet. One difficulty posed by both the SRCE and the conventional DOGM calculators is that the construction Geomorphic Reclamation method doesn't fit well with them. We may need additional cost units and guidance as the form of the Surety Estimate is brought in line with the expected formatting.

Responses to comments are marked in blue if completed and dark red if work is ongoing.

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INITIAL REVIEW OF REVISED NOTICE OF INTENTION TO COMMENCE LARGE MINING OPERATIONS

Anfield Resources Holding Corporation
Velvet Resources Mine

General Comments:

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
1.	General	The Division may have additional comments based on the review responses.	kmc	
2.	Form	Please note that the Amendment was filled out as Anfield Energy Inc. where there is no records on file with the Utah Department of Commerce. The Notice is listed under Anfield Holding Corp but has a renew date of 9/30/2024. In addition, Joshua Bleak, not John Eckersley, is the only authorized individual to sign. Please be aware that the Operator must be registered with the Utah Department of Corporations. The Notice, reclamation contract, and the Bond must all match. Joshua Bleak and John Eckersly have updated the MREV, Operator and Notice of reclamation contract. Joshua Bleak is the signatory.	cbr CDW	

R647-4-104 – Operator Information and Surface and Mineral Ownership

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
3.	Attachment A	Please list the name, address, and field office associated with state and federal landownership in section R647-4-104.6 Attachment A provides the Federal unpatented mining claim and state leases but does not provide contact information. Information has been added to Attachment A	cbr CDW	

R647-4-105 - Maps, Drawings & Photographs

General Map Comments

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
4.	Surface Faculty Map, Operations and Reclamation plans	Information on explosive storage areas must only be listed in a confidential section of the NOI. The ATF does not want the location of explosives to be readily available to the public. Created Attachment N – CONFIDENTIAL, add powder mag detail CON-1 to it. Shown area as general disturbance w/o structures in OP-5 and DET-1	whw CDW	

105.1 - Topographic base map, boundaries, pre-act disturbance

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
5.	Omission	The NOI states that there are no wetlands or perennial streams present within the Velvet-Wood project area. The Division recommends that the operator review the U.S. Fish and Wildlife Service to present mapped waters of the U.S. https://fwsprimary.wim.usgs.gov/wetlands/apps/wetlands-mapper/  The above image depicts mapped waters of the US in the area of the portal.	cbr CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
		 The above image depicts mapped waters of the US in the area of the dewatering ponds.  The image above depicts mapped water of the US near the proposed surface disturbance of the wood project. Responses added to 106.7 and 109.3: Although the national wetland inventory shows wetlands in the area of the proposed dewatering ponds, they do not currently exist. Other mapped wetlands are outside the proposed disturbance areas		

105.3 - Drawings or Cross Sections (slopes, roads, pads, etc.)

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
6.	Omission	R647-4-105.3.16. Baseline information maps and drawings including soils, vegetation, watershed(s), **geologic formations and structure**, contour and other such maps which may be required for determination of existing conditions, operations, reclamation and postmining land use Please provide a geologic map. Added OP-6 Geologic Map	cbr CDW	

105.4 - Photographs

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
7.	Optional	R647-105.4 in the NOI states: "No photographs have been provided." The rule for this section is that "The operator may submit photographs (prints) of the site sufficient to show existing vegetation and surface conditions." Photographs are helpful to be able to review features for the bond, establish baseline vegetation, and current conditions of the permit. Site Photographs added to 105.4	kmc CDW	

105.5 – Underground and Surface Mine Development Maps

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
8.	Omission	R647-105.5.5. is for "Copies of the underground and surface mine development maps." The operator provided underground development maps but they were not referenced in the this section of Text in the NOI. Reference to OP-3 Overall Mine Map added to 105.5	kmc CDW	

R647-4-106 - Operation Plan

General Operation Comments

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
9.	R647-4-104.6	SITLA – Please be aware that SITLA has changed its name to Utah Trust Lands Administration. All references to SITLA changed to Utah Trust Lands Administration (UTLA formerly SITLA)	cbr CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
10.	R647-4-104.6	SITLA ownership (see Attachment A) Note: Attachment A shows that the SITLA lease expired 05/31/2024. Please remove reference to SITLA being a current land management agency. If in the future SITLA lease are include then you can amend/revise the permit. ML No. Updated to current 54557 and amended in Attachment A	whw CDW	

106.3 - Estimated acreages disturbed, reclaimed, annually/sequentially

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
11.	R647-4-106.3	Please remove the phases "which is above the 22 acres listed in the original mine permit" "Mining will re-disturb these areas and disturbed an additional 6 acres of land for new roads, ventilations and water treatment for the Wood development" those phases will be confusing to readers not familiar with the permit history. These Phrases have been removed.	whw CDW	
12.	R647-4-106.3	Please include a table that lists all disturbed areas and the associated acres. Disturbance Acres Table 5 added to 106.3 and OP-5	whw CDW	
13.	R647-4-106.3	Please list in the table what areas have been previously disturbed and then given partial or full bond release and what undisturbed areas will be disturbed. Previously disturbed Acres are listed in Table 5 where the newly/undisturbed acres are the difference between column B and C.	whw CDW	
14.	R647-4-106.3	Please include maps and tables that give a detailed description of all lands to be covered by the reclamation bond. This includes but not limited to: all roads that will be created or upgraded by the operator, detailed map of the water treatment facility, all existing and proposed vents, all other underground openings. Naming and details of disturbance, Buildings and equipment unformalized and carried through surety calc. Spread Sheet Added to Attachment F.	whw CDW	

106.6 - Plan for protecting & re-depositing soils

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
15.	R647-4-106.6	This section states that the maximum height of topsoil stockpiles will be 16ft. However, in the "Topsoil Stockpile Areas" description under the Surface Facilities section is states that topsoil stockpiles will be no higher than 12ft. Update either section for consistency and accuracy. Sections Updated to reflect a maximum height of 16ft.	mm CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
16.	R647-4-106.6	This section states that there is estimated to be 1,700 banked cubic yards (bcy) of available topsoil that could be stripped. However, in Figure OP-4, the sum of the proposed cubic yards of stripped topsoil is 1,160 (not counting the Potential Topsoil Strip Area). For consistency, ease of reference and ease of understanding the topsoil balance, please check these numbers and include the most realistic number of cubic yards of available topsoil in this section. If 1,160 as shown in the figure is more precise and realistic, then include that number and explanation in this section. Anticipated coversoil volumes have been updated and unified across figures.	mm CDW	
17.	R647-4-106.6	The text states that a topsoil stockpile seed mix will be used. Please propose a topsoil stockpile seed mix for the Division and BLM to review. The Division and BLM can recommend a seed mix if necessary. Stockpile seed mix requested, and received from DOGM. Added to section 106.6.	mm CDW	

106.7 - Existing vegetation - species and amount

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
18.	R647-4-106.7	The information in this section does not adequately describe cover levels sufficient to establish revegetation success standards in accordance with R647-4-111. Please provide a percent cover based on survey results or provide the percent cover of adjacent, undisturbed land to use as a reference state. The Division does not consider tree species in establishing a percent cover for revegetation standards. Additional discussion added to 106.7.	mm CDW	

106.8 - Depth to groundwater, extent of overburden, geologic setting

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
19.	Omission	R647-4-106.8 Depth to groundwater, extent of overburden material and geologic setting. Depth to ground water has been provided. However, the overburden and geologic setting have not been addressed. Please provide a detailed geologic setting. Additional discussion/description of Overburden and Geologic Setting added to 106.8.	cbr CDW	

106.10 - Amounts of material extracted or moved (including ore, waste, topsoil, etc.)

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
20.	Omission	R647-4-106.10. Information regarding the amount of material (including mineral deposit, topsoil, subsoil, overburden, waste rock, or core hole material) extracted, moved or proposed to be moved. This section was not included. However, there are information related to this section listed in other sections (R647-4-106.3 and R647-4-109.4) of the permit which can be referenced here. 106.10 added referencing 106.4 and 106.6.	kmc CDW	

R647-4-108 - Hole Plugging Requirements

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
21.	R647-4-108	All ventilation shafts/holes must be plugged in accordance with R647-4-108. Please provide a statement to this effect. If the shafts are dry, then a 5-foot cement plug must be placed. If the shafts encounter water, then they must be plugged to prevent water migrating. Reference made to R647-4-108 and detail abandonment made to conform to UT AMRP Master construction Specifications, Drawing 4.	whw CDW	

R647-4-109 - Impact Assess

109.2 – Potential impacts to threatened & endangered wildlife/habitat

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
22.	R647-4-109.2	Section 106.7 and the report in Attachment B state that only 4 species (not 8) have potential to occur within the project area. Please update for consistency and accuracy. Corrected in 109.2 to four from eight.	mm CDW	

109.5 - Actions to mitigate any impacts

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
23.	Omission	Please provide a general narrative, this section can reference section 106.2, 106.4, and 109.1. Discussion/reference added.	cbr CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
24.	Omission	Surface hydrology mitigation is generally described in sections 109.1 and 109.4, please provide a general narrative and reference the section stated. Discussion/reference added.	cbr CDW	
25.	Omission	Groundwater hydrology mitigation is generally described in section 109.1, please provide a general narrative and reference this section. Discussion/reference added.	cbr CDW	

R647-4-110 - Reclamation Plan

110.2 – Reclamation of roads, highwalls, slopes, impoundments, drainages, pits, piles, shafts, adits, etc

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
26.	R647-4-110.2	Sufficient information is provided in is section to address concerns related to Surface hydrology. Thank you.	cbr CDW	
27.	R647-4-110.2	Please provide a general narrative regarding groundwater hydrology at the time of reclamation. Narrative added to 110.2.	cbr CDW	
28.	R647-4-110.2	It is likely that the site does not contain enough topsoil to place 3-12 inches of topsoil across all reclaimed surfaces. The plan in this section mentions that topsoil will be imported from an approved off-site source if necessary. If any sources have already been identified, please mention them here. Any off-site soil or soil amendments must be reviewed/approved by the Division. All references to top-soil placement have been unified to read a minimum of 3inches rather than a range. If possible, more will be placed. If needed, additional topsoil will be secured from a source of similar quality. At this time a source that has not been identified as topsoil quality will be tested upon salvage and the Division consulted for review of possible importation sources.	mm CDW	

110.5 - Revegetation planting program

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
29.	R647-4-110.5	The revegetation success standard is 70% of the pre-mining percent cover, not 70% total cover. Corrected.	mm CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
30.	R647-4-110.5	Please propose a final reclamation seed mix for the Division and BLM to review. The Division can recommend a seed mix if necessary. Seed mix provided by DOGM added to section.	mm CDW	
31.	R647-4-110.5	For ease review and without having to go to go to the reclamation cost estimate sheets in Attachment F, please briefly describe the revegetation methods in this section. Brief description added.	mm CDW	

110.6 - Certification

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
32.	Omission	The submittal has left the statement of reclamation blank. Please make sure the plan is certified. This can be done by utilizing the Division standard LMO template that has a signature/certification section. https://ogm.utah.gov/wp-content/uploads/2023/12/mr-lmo-2011.doc Signature section added.	cbr CDW	

R647-4-113 – Surety

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
33.	Surety General	Some of the wage rates are done using 2023 costs while the equipment was done with 2024 equipment rates. The numbers used need to be consistent. Please utilize the 2025 rates (such as the new escalation factor of 4.22%). The Division can supply reference numbers upon request. Thank you. Understood. Surety Calculation ongoing.	kmc CDW	
34.	Surety General Comment	The Division usually separates the demolition costs from the earthwork costs. There is no specific demolition costs listed in the reclamation cost estimate. The Division made assumptions about the demolition costs. Those costs that will be submitted are spreadsheets attached to this document. Please review the demolitions costs. Surety Calculation ongoing. Demolition is in the process of being split from earthwork. Disposal will also be listed separately.	whw CDW	
35.	Surety Demolition	Please include the cost for the hydraulic hammer that will be used to breakup the concrete. That cost must be in addition to the excavator. Surety Calculation ongoing.	whw CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
36.	Surety Earthwork	Equipment choice – for removing the eastern edge of the waste rock pile the operator proposes using truck and shovel. However, since the total haul distance is 300 feet one-way the operator may fine using front end loader more economical. See Caterpillar handbook. Loading operations have been specified as an excavator and shovel to act as a conservative estimate of the reclamation costing.	whw CDW	
37.	Surface Facilities Map – Operations Plan – Reclamation Plan	Please ensure that the name of all surface facilities is constant in the NOI. For example, in the operations plan a 12'x60' structure is called Mine Office while on the surface facilities map the 24'x60' building is referred to as office/employee facility, on the facilities map a 40'x80' building is listed as shop & warehouse while in the operations plan it is listed as maintenance shop and warehouse. Another example is power poles owned by the Operator vs power poles owned by the Power company. All names and dimensions are now unified across text, figures and surety.	whw CDW	
38.	Surface Facilities Map – Operations Plan – Reclamation Plan	Please ensure that all surface facilities are listed in the operation plan, the reclamation plan, the surface faculties map and the bond. For example, in the operation plan the employee facility and dry room are listed as a 24'x60' structure but is not listed on the surface facilities map or as a line item in the reclamation cost estimate. All surface facilities unified across documents and figures.	whw CDW	
39.	Operation Plan Surface Facilities	Please list the height of each structure. This is needed to calculate the reclamation cost. All structure heights added.	Whw CDW	
40.	Operation Plan Surface Facilities	Will large structures like the Maintenance Shop and Warehouse have foundations? That information is needed to calculate the reclamation cost estimate. The proposed Maintenance Shop & Warehouse, Office & Employee Facility and the Utilities Pad will have 6" thick slabs on grade. This information has been added to the figures and text and is being incorporated into the Surety Calculation.	whw CDW CDW	
41.	Reclamation Plan 110.4	Trailers and buildings will be disposed of in off-site landfills. Please state which landfill the material will be taken to. The Division needs that information to determine haul distances and dump fees. The Division does allow for steel to be taken to a recycling facility and be disposed of at no cost. Statement made to dispose of at the City of Monticello Landfill.	whw CDW	
42.	Operation Plan 106.1	Main Office – Please list height of structure and dimensions for concrete pad. All dimensions described in DET-1 and Surety calc.	whw CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
43.	Operation Plan 106.1	Please list dimensions and equipment/structures for the air compressor station. The Air compressor will be located at along the outside of the south wall of the Maintenance Shop & Warehouse not included on the foundation. It will be a modular unit approximately 13.5'Lx6'Wx7'H. This has been added to the figures and will be incorporated into the surety calculation.	whw CDW CDW	
44.	Operation Plan 106.1	Please list dimensions and equipment/structures for mine vents – total nine. Added to text, DET-1 and surety.	whw CDW	
45.	Operation Plan 106.1	Water supply system – Please include dimensions for the 5,000-gallon water tank, concrete pad. Dimensions have been added to DET-1 and surety.	whw CDW	
46.	Reclamation Plan 110.2	Please include a detailed description of the disposal of liners materials. Statement needed Statement added regarding disposal at a licensed facility. Liners will be present underneath water treatment tanks and fuel storage tanks. After removal of the tanks, the liners and any sediment that has accumulated on them over time will be folded up and taken to the City of Monticello Landfill or Lisbon Valley Mining Solid Waste for disposal.	whw CDW	
47.	Reclamation Plan 110.2	Please provide an alternative disposal plan for stockpiled ore. If the operator forfeits on the bond, there is no guarantee that the operator owned mill would be able properly handle the ore. Statements added to 110.2 reflecting alternatives: If the ore stockpiles cannot be shipped to the mill due to economic or other conditions, they will be treated as marginal material and disposed of with other such material within the waste rock pile or hauled and backstowed underground as described above. After regrading and redistribution of salvaged topsoil, revegetation will adhere to the specifications as provided in Attachment F.	whw CDW	

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
48.	Reclamation Plan 110.2	Please include detailed reclamation cost estimate for permanent closure of the declines. Please describe the closure in more detail and update Figure RP-2. Will there be any seals besides the bulkhead? The plan calls for backfill which may have subsidence. Mine portal closure details are shown on Figure RP-2. Permanent mine closure will employ a grouted rock bulkhead to be constructed in the decline at a location where a sufficient thickness of competent roof rock exists to prevent future subsidence of the mine void which may report to the surface. The bulkhead shall extend a minimum of 2 mine heights length down the decline (approximately 24 ft) and consist of waste concrete from building, ore stockpile, and unclassified materials. This bulkhead material will be grouted in following placement using cementitious grout using tremmie or other piping from the portal to the face of the bulkhead and pumped until refusal. The remaining decline upslope of the bulkhead will be shot down and the surface re-graded for positive drainage away from the reclaimed portal.	whw CDW	
49.	Reclamation Plan 110.4	Disposal of petroleum products, tanks and waste products. Please include an alternative disposal method for all petroleum products, tanks and waster products. The Division cannot assume that they can be returned to a vendor. Instead, there should be an alternative detailed plan that includes cost for the disposal of such materials. Details added: At the time of mine closure, the remaining petroleum products on site will be used for their intended purpose, transported to another facility, or returned to the vendor. The used oil will be picked up by a certified hydrocarbon recycler, such as Rock Canyon Oil. After removal of their contents, the tanks will be shipped to another facility, sold, or properly decommissioned and recycled at the Canyonlands Transfer Station. The liner underneath the fuel station will be exposed, cut into sections, and hauled to the City of Monticello Landfill for disposal. Any soil found to have petroleum/oil contamination would be characterized, removed from the site, and taken to the City of Monticello Landfill. The solvent station and any remaining solvent will be returned to the vendor. The road stabilizing products will be used to control dust during reclamation and the tanks will be removed and shipped off site. For the surety calculation: Two 6,900-gal vacuum truck loads hauling 250 mi to the Rock Canyon Oil facility are being added to the disposal cost estimate.	whw CDW CDW	
50.	Air Quality Plan	In various parts of the plan the capacity of the propane tank is listed as 1,000 gallons, however in the air quality plan it is listed as 2,000 gallons. Please clarify. Text and figures corrected to 2,000 gallons.	whw CDW	

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Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
51.	Wood Water Treatment Facility	Please include the quantity of material and production rate to be moved by the excavator, dozer and on-highway truck. Surety Calculation ongoing.	whw CDW	
52.	Wood Vent Shafts	Please include the quantity of material and production rate to be moved by the excavator, dozer and on-highway truck. In addition, please include costs to plug the shafts. Surety Calculation ongoing.	whw CDW	
53.	Roads	Any upgrades to the existing roads will need to be included as part of the bond. Surety Calculation ongoing. Understood. Would that upgrading be included in bonding the additional disturbance or by length of the road feature.	kmc CDW	
54.	Velvet Powerline Reclamation	Please include the number of power poles and approximate dimensions of the power poles owned by the Operator. Any power poles owned by the utility will not need to be included (i.e. Section R647-4-110.3). The Bond currently lists that the two truckloads of power pole material will be shipped to the Shootarang mill. Discussion of power poles limited to statement of interest in its pursuit in the long-term using a separate amendment. No Surface facilities will remain on site following demolition and reclamation.	whw CDW	
55.	Velvet Portal Reclamation	Please include the quantity and productivity for the material to be removed for reclaiming the Velvet portal. Also, include the cost for construction of the bulkhead to seal the portal. Surety Calculation ongoing.	whw CDW	
56.	Velvet Water Treatment Facility	Please include the quantity of material and production rate to be moved by the excavator, dozer and on-highway truck. Surety Calculation ongoing.	whw CDW	
57.	Velvet Vent Shafts	Please include the quantity of material and production rate to be moved by the excavator, dozer and on-highway truck. In addition, please include costs to plug the shafts. Surety Calculation ongoing.	whw CDW	
58.	Reconfigure SWPPP Controls	Please include the quantity of material and production rate to be moved by the dozer. Surety Calculation ongoing.	whw CDW	
59.	Topsoil	Please include costs for topsoil placement. 1,700 bcy of material Surety Calculation ongoing.	whw CDW	
60.	Ripping	Please include costs for ripping. Surety Calculation ongoing.	whw CDW	

BRS, Inc. Engineering
1130 Major Ave.
Riverton, WY 82501
E-Mail: brs@bresnan.net
Phone: 307-857-3079 Fax: 307-857-3080

Comment #	Sheet/Page/ Map/Table #	Comments	Initials	Review Action
61.	Generator Pads	Please include costs for removal/disposal of concrete pads for the generators. Surety Calculation ongoing.	whw CDW	
62.	Drainage Construction	Please include costs for the construction of the drainages. This includes any culverts that will be left and the channel reclamation design of waste rock dumps. Surety Calculation ongoing.	whw CDW	
63.	Bulkhead	Please include costs for the construction of the bulkhead in the portal and costs for explosives to seal the portal. Surety Calculation ongoing.	whw CDW	

Thank you for all your hard work and consideration,

Carl Warren

Carl Warren, PE, PG
Senior Engineer | BRS Engineering
Office (307) 857-3079 | Fax (307) 857-3080 | Cell (307) 709-0078
BRSEngineering.com
1130 Major Avenue, Riverton, WY 82501
CWarren@BRSEngineering.com

FORM MR-REV

INSTRUCTIONS to REVISE or AMEND MINING OPERATIONS NOTICE OF INTENTION

When an operator intends to revise or amend a mining operation, a **notice** to Amend or Revise the mining and reclamation plan **must be submitted** to the Division **and approved prior to creating any disturbance beyond what has already been approved.** The notice must include all information, concerning the revision or amendment, that would have been required if it had been included in the original Notice of Intention (NOI).

"REVISION" means a **significant change** to the approved Notice of Intention to Conduct Mining Operations, which will increase the amount of land affected or alter the location and type of onsite surface facilities such that the nature of the reclamation plan will differ substantially from the approved Notice of Intention. Revisions require a formal public notice of tentative approval and may require a change in the amount of reclamation surety.

"AMENDMENT" is an **insignificant change** to the approved Notice of Intention. An amendment requires Division approval, but does not require public notice.

The Division will determine whether a request for change is significant or insignificant on an individual case-by-case basis.

Instructions:

- Changes to the mining and reclamation plan are made by providing a completely new plan or by adding, replacing, or removing pages to the current plan. Detailed instructions for adding or replacing pages and maps must be included (please identify on the attached form MR-REV-att).
- Text changes should be shown in a redline/strikeout format.
- The amended application should be accompanied by a cover letter: referring to the permit number, operator name and mine; describing the contents; and referencing any Division action that initiated the change (i.e. Notice of Violation, previous review, Division Order).
- The submitted revision or amendment must be complete and should not rely on additional materials that will be submitted at a later date.
- Form MR-REV-att, or equivalent, must be submitted with the application for change.

After the Division conditionally approves the change, two clean copies will be requested which will be stamped “approved” and one copy returned for your copy of the mining and reclamation plan. The change is now approved and you may proceed with your plans.

Identify any changes this modification will have to:

I. General Information (R647-4-104)

- Location of Proposed Activities:
- COUNTY
- TOWNSHIP, RANGE, SECTION(S) (Identify to 1/4, 1/4 section)

Ownership of Land Surface:

- Private (Fee) - Identify Owners Name(s)
- State of Utah (SITLA) lands, Public Domain BLM), National Forest (USFS)

Ownership of Minerals:

- Private (Fee) - Identify Owners Name(s)
- State of Utah (SITLA) lands, Public Domain BLM), National Forest (USFS)
- **BLM Lease or Project File Number(s) and/or USFS assigned Project Number(s**
- **Utah State Lease Numbers(s)**

II. MAPS, DRAWINGS & PHOTOGRAPHS (Rule R647-4-105)

Appropriate maps, drawings, plates, etc. should be provided that are pertinent to the revision, or amendment of mining operations. Please provide a revised map outlining the previously approved and the new proposed disturbed area boundaries. These materials should be prepared according to the requirements of Rule R647-4-105.

III. OPERATION PLAN (Rule R647-4-106)

All appropriate information requirements outlined under Rule R647-4-106 must be addressed in the application. Identify additional proposed surface disturbance. Include the total number of acres to be affected by the revision or amendment.

IV. IMPACT ASSESSMENT (Rule R647-4-109)

Provide information required under Rule R647-4-109 regarding projected potential surface and/or subsurface impacts that may be associated with the proposed change(s) in mining operations.

V. RECLAMATION PLAN (Rule R647-4-110)

Outline any proposed changes to the originally approved reclamation plan. Address all appropriate sections of Rule R647-4-110 as they apply to the proposed change(s) in mining operations.

VI. VARIANCE (Rule R647-4-112)

Identify any requests for variance from the requirements of rules R647-4-107, -108, or -111. A narrative justification and alternate methods or mitigating measures must be included for each variance request.

VII. SURETY (Rule 647-4-113)

Reclamation Surety:

Indicate whether the proposed activities will change the amount of work required to reclaim the mine site. If significant changes will result, then an itemized reclamation cost estimate should be provided (and attached) with direct reference to the specifics of the proposed change(s). This information will be used to assist the Division in determining any reclamation surety adjustments required for the operation.

Form MR-REV-att (DOGM – Revise/Amend Change Form)
(Revised September 14, 2005)

Application for Mineral Mine Plan Revision or Amendment

Operator: Anfield Resources Holding Corp.

Mine Name: Velvet **File Number: M/**0370040/

Provide a detailed listing of all changes to the mining and reclamation plan that will be required as a result of this change. Individually list all maps and drawings that are to be added, replaced, or removed from the plan. Include changes of the table of contents, section of the plan, pages, or other information as needed to specifically locate, identify and revise or amend the existing Mining and Reclamation Plan. **Include page, section and drawing numbers as part of the description.**

DETAILED SCHEDULE OF CHANGES TO THE MINING AND RECLAMATION PLAN			
			DESCRIPTION OF MAP, TEXT, OR MATERIALS TO BE CHANGED
☐ ADD	☒ REPLACE	☐ REMOVE	Full Document
☐ ADD	☐ REPLACE	☐ REMOVE	
☐ ADD	☐ REPLACE	☐ REMOVE	
☐ ADD	☐ REPLACE	☐ REMOVE	
☐ ADD	☐ REPLACE	☐ REMOVE	
☐ ADD	☐ REPLACE	☐ REMOVE	
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☐ ADD	☐ REPLACE	☐ REMOVE	
☐ ADD	☐ REPLACE	☐ REMOVE	
☐ ADD	☐ REPLACE	☐ REMOVE	

I hereby certify that I am a responsible official of the applicant and that the information contained in this application is true and correct to the best of my information and belief in all respects with the laws of Utah in reference to commitments and obligations, herein.

Joshua Bleak
Print Name

President
Sign Name, Position

3/27/2025
Date

Return to:

State of Utah
Department of Natural Resources
Division of Oil, Gas and Mining
1594 West North Temple, Suite 1210
Box 145801
Salt Lake City, Utah 84114-5801
Phone: (801) 538-5291 Fax: (801) 359-3940

FOR DOGM USE ONLY:
File #: M/ /
Approved:
Bond Adjustment: from ($)
to $

O:\FORMS\MR-REV-att.doc

UTAH DIVISION OF OIL, GAS & MINING

Credit Card Payment Receipt

Your payment was successfully processed.

Please print this page as a receipt for your records.

Item	Quantity	Item Amount	Total
Annual Large Mine Permit Renewal (up to 50 acres) *Enter your Permit Number ex:M/001/0001, Mine Name, and Operator Name below.*	1	$500.00	$500.00
Total Amount:			**$500.00**

Payment Processing Details

Order Number:	7811188
Date of Transaction:	04/29/2024
Amount Charged:	$500.00
Name on Card:	Carl Warren BRS INC
Credit Card Number:	***************4032
Credit Card Type:	Visa

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Velvet-Wood Mine
Plan of Operations

Anfield Energy Inc.
April 2025

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Introduction

This Plan of Operation addresses mining operations at the Velvet-Wood Mine in San Juan County, Utah located in T31S R25E Sections 1, 2, 3, 4, 10, 11, 12, 13, and 14, and T31S R26E Sections 6 and 7 (see Figure LM-1). The Velvet Mine was permitted as a 22-acre Large Mine under Mine Permit M370040. This Plan of Operations, submitted by Anfield Resources Holding Corp (ARHC), is an update to the existing Plan of Operations submitted by Atlas Minerals, the previous operator, and has been formatted to address specific regulatory items identified in the Utah Administrative Code R346-4 and Bureau of Land Management (BLM) guidance.

This Plan of Operation includes specific operating actions and controls, reclamation actions, an estimate of reclamation surety based on third party costs and technical bases for how the actions meet the regulatory requirements of the State of Utah and the BLM.

Reclamation of the Velvet Mine was initiated in the early 1990’s by Umetco and by Uranium One in the early 2010’s. A return to operation requires that the mine portal and underground workings be rehabilitated with the partially flooded mine workings being dewatered and surface facilities restored. The restoration of operations under Anfield will occur primarily on existing mine permit areas and within areas of previous disturbance. The total mine area proposed in this plan is approximately 28 acres. Within 200 ft of the proposed new mine disturbance, a total of 73 acres has been previously disturbed by previous mining, which has been reclaimed and released from the bond.

Dewatering of the mine will occur in the same manner originally permitted, with water being pumped from vent shaft C with a submersible pump, treated at the surface and discharged to the adjacent ephemeral drainage under UPDES permit UT0025810 (See Attachment J). Initial mine water treatment will be performed using a pilot treatment plant authorized by UDWQ without a Ground Water Discharge Permit. The application to UDWQ for this pilot treatment plant is currently under review. During this phase, additional hydrogeologic characterization will be performed to support a Ground Water Discharge Permit application to the UDWQ for the long-term water treatment system.

Mine ores and waste will be brought to the surface and deposited in existing waste rock storage areas. Significant quantities of mine waste (unclassified and mineralized waste rock) will also be backstowed in the exhausted workings and not brought to the surface. Ore will be stockpiled and loaded in an area on top of the work pad expansion constructed with unclassified waste from constructing declines. All mine portal and surface facilities drainage will be captured in storm water control structures designed to contain all site runoff without discharge. Storm water retained in the structures will be hauled via truck to the mine dewatering treatment facility for treatment and discharged under the UPDES permit or will be used in the underground mining process. These waters will then return to the lower vent shaft area of the mine where they will be pumped to the surface with the mine dewatering flows for treatment and permitted discharge.

I. Rule R647-4-104 - Operator(s), Surface and Mineral Owners

Provide the name, address, and telephone number of the individual or company who will be responsible for the proposed operation. **Business entities listed as the Permittee / Operator, must include names and titles of the corporate officers on a separate attachment.**

104.1 - Mine Name

Mine Name: *Velvet – Wood Mine*

104.2 - Operator Information

Operator Name: ANFIELD RESOURCES HOLDING CORP.
Mailing Address: 10808 S RIVER FRONT PARKWAY, SUITE 321
City, State, Zip: SOUTH JORDAN, UT 84095
Phone: 801-984-3359 Fax: 801-984-4302
E-mail Address: ____
Taxpayer Identification Number: 90-1072322

Type of Business: Corporation (X) LLC ( ) Sole Proprietorship (dba) ( )
Partnership ( ) General ____ or ____ limited **or:** Individual ( )

Entity must be registered (and maintain registration) with the State of Utah, Division of Corporations (DOC) www.commerce.utah.gov.

Are you currently registered to do business in the State of Utah? (X) Yes ( ) No
Entity # 8804532-0142
If no, contact www.commerce.utah.gov to renew or apply.
Local Business License # ____ (if required)
Issued by: County ____ or City ____

Registered Utah Agent (as identified with the Utah Department of Commerce) *(Leave blank if the operator is an individual)*:

Name: INCORP SERVICES INC.
Address: 285 W TABERNACLE ST STE 201
City, State, Zip: SAINT GEORGE, UT 84770-3794
Phone: ____ Fax: ____
E-mail Address: ____

Serial Number of Existing PoO Replaced by This PoO: UTU-68060

104.3 - Permanent Address

Permanent Address: 10808 S RIVER FRONT PARKWAY, SUITE 321
SOUTH JORDAN, UT 84095
Phone: 801-984-3359 Fax: 801-984-4302

104.4 - Contact Person(s)

Please provide as many contacts as necessary.
Name: JOSHUA BLEAK Title: DIRECTOR
Address: 10808 S RIVER FRONT PARKWAY, SUITE 321
City, State, Zip: SOUTH JORDAN, UT 84095
Phone: 480-809-5982 Fax: 801-984-4302
Emergency, Weekend, or Holiday Phone: 480-809-5982
E-mail Address: josh.bleak@gmail.com

Contact person to be notified for: permitting (X) surety (X) Notices (X) (please check all that apply)

104.5 - Location of Operation

County: San Juan (see Figures OP-1 and Attachment A for locations and claim blocks)

T31S, R25E

Section 1	**Section 2**	**Section 3**	**Section 4**
SE ¼ of SE ¼	NW ¼	Entirety of Section 3	NE ¼ of SE ¼
SW ¼ of SE ¼	SW ¼	Except for	SE ¼ of SE ¼
	NE ¼	N ½ of NW ¼ of NW ¼	NE ¼ of NE ¼
	SE ¼		SE ¼ of NE ¼

Section 10	**Section 11**	**Section 12**	**Section 13**
NW ¼ of NW ¼	NE ¼ of NW ¼	N ½ of NW ¼	NE ¼ of NE ¼
NE ¼ of NW ¼	NE ¼ of NE ¼	N ½ of NE ¼	
NW ¼ of NE ¼	NW ¼ of NE ¼	SE ¼ of NE ¼	
NE ¼ of NE ¼		NE ¼ of SE ¼	
		SE ¼ of SE ¼	

T31S, R26E

Section 6	**Section 7**
S ½ of SW ¼	NW ¼
SW ¼ of SE ¼	W ½ of NE ¼
	SW ¼
	NW ¼ of SE ¼

104.6 - Ownership of Land Surface

Land ownership is BLM and UTLA (See Attachment A)

104.7 - Owner(s) of Record of the Minerals to be Mined

Mineral ownership is controlled by unpatented BLM claims and Utah Trust Lands Administration (UTLA, formerly SITLA) lease (See Attachment A)

104.8 - BLM Lease or Project File Number(s)

BLM Claim Numbers: (See Attachment A)

Utah State Lease Number(s): ML 54557, (See Attachment A)

Name of Lessee(s): (See Attachment A)

104.9 - Adjacent Landowners

BLM and UTLA (See Figure OP-1)

Lisbon Valley Mining Co. LLC
920 S County Road 313
Lasal, UT 84530

Robinson Livestock Inc.
264 North 100 West
PO Box 224
Monticello, UT 84535

104.10 - Notification of Landowners

BLM and State landowners will be notified with submittal.

Notification of Lisbon Valley Mining and Robinson Livestock is in progress.

104.11 - Legal Right

Does the Permittee / Operator have the legal right to enter and conduct mining operations on the land covered by this notice? Yes

II. Rule R647-1-105 - Maps, Drawings & Photographs

105.1 - Topographic Base Map

Figure OP- 1 Ownership and Claim Map includes a topographic base. Figure OP-2 Existing Disturbance presents the current state of the land. Figure LM-1 Overall Location and Access shows the nearby towns and access routes to the site. These figures are located in Appendix I.

105.2 – Surface Facilities and Mine Development Maps

Figure OP-5 Overall Surface Facility Map, Figure DET-1 Velvet Surface Facilities, Figure DET-2 Velvet Water Treatment, and Figure DET-3 Wood Water Treatment are the relevant figures for this section. These figures are located in Appendix I.

105.3 – Additional Maps, Drawings, and Cross Sections

Figure OP-4 Topsoil Strip Estimate is provided to explain the potential topsoil removal for surface facilities and is located in Appendix I. RP-1 Reclamation Plan and RP-2 Reclamation Details are provided as figures for the written reclamation plan and are located in Attachment F, Reclamation Plan and Bond Estimates.

105.4 – Photographs

Photographs of the site on undisturbed and disturbed ground taken in May of 2023 are provided below.


5/18/23, 9:49:02 AM
UTM 665147 4220122
286 deg(T) 2019 m
ACCURACY 5 m
DATUM NAD83
Velvet Mine
Sagebrush
Plateau


5/17/23, 9:44:47 AM
UTM 661124 4220357
200 deg(T) 2017 m
ACCURACY 5 m
DATUM NAD83
Velvet Mine
RockyPJ
Overview


5/18/23, 9:07:39 AM
UTM 665646 4219803
140 deg(T) 2049 m
ACCURACY 5 m
DATUM NAD83
Velvet Mine
Disturbed


5/18/23, 12:37:10 PM
UTM 664797 4218969
90 deg(T) 2111 m
ACCURACY 4 m
DATUM NAD83
Velvet Mine
EastSide
PJ Overview

105.5 – Underground and Surface Mine Development Maps

Figure OP-3 Overall Mine Map provides the planned layout of the underground mine development drifts.

III. Rule R647-4-106 - Operation Plan

106.1 - Minerals Mined

The minerals being mined are uranium and vanadium.

106.2 - Type of Operations Conducted, Mining Method, Processing etc.

The Velvet Mine Uranium Project was initially drilled during the 1970's with the principal exploratory work and drilling completed by Gulf Minerals Corporation. Gulf sold the property to Atlas in the late 1970's. Atlas' Velvet Mine commenced operations in 1979 in Section 3 and advanced to the boundary with Section 2. Atlas completed feasibility studies for mining Section 2 mineral resources including hoisting and haulage of ores to their Moab mill for processing in 1980. These plans were never executed due to low uranium prices in the 1980's and the property was sold by Atlas Minerals. Minerals Recovery Corporation (MRC) of Lakewood, Colorado purchased the property from Atlas. MRC was the operating arm of Wisconsin Public Service Company. Additional drill holes were completed in 1981 and 1984 by MRC. A feasibility study was completed by Minerals Recovery Corp. in 1983. Subsequently, Wisconsin Public Service Company exited the uranium business. The Velvet Mine in Section 3 closed in 1984. The Velvet

Mine property was acquired by Umetco Minerals Corp. in 1989. Umetco was interested in the property due to the vanadium content of the remaining reserves. Umetco held the Section 3 property until the mid-1990's at which time the property was transferred to US Energy (USE). Through the acquisition of the uranium assets of USE and Energy Metals Corporation (EMC), Uranium One controlled the mineral rights to those portions of Section 2, T32S, R25E; and mineral rights for Section 3 and 4 of T31S, R25E, totaling approximately 494 acres. The property was then sold and transferred to Anfield Energy Inc. in 2015, who then published a preliminary economic assessment in 2023.

The Wood mineralization was discovered in 1975 by Atlas in Section 6, Township 31 South, Range 26 East (Chenoweth, 1990). Uranerz U.S.A. Inc. (Uranerz) controlled the Wood area of the project during the 1980s when most of the initial exploration took place. A total of 120 known historic rotary drill holes were completed by Uranerz from 1985 through 1991. The exploration resulted in the discovery of three mineralized zones in the Cutler Formation. The most important of these, the Wood mineralized body, was outlined in 14 holes that intercepted high grade material. In the 1990s Uranerz's mining claims were allowed to lapse.

In 2004, Energy Metals Corporation staked new mining claims over the Wood area. Uranium One gained control of the property through the purchase of Energy Metals Corporation in 2007. No production has ever occurred in the Wood area of the Project. Refer to Figure OP-1, Ownership and Claim Map.

Anfield plans to access the old Velvet Mine workings and begin development on the Velvet-Wood mineralization. The Velvet-Wood Mine mineralization is located within the Lisbon Valley physiographic province in San Juan County, Utah. The project is approximately 10 miles south of La Sal, Utah (see Figure LM-1) and is located at approximate Latitude 38^{o} 07' North and Longitude 109^{o} 09' West. The project area is located primarily on a dipping bench above the Lisbon Valley, with elevations averaging 6,800 feet above sea level.

Figure OP-2, Existing Disturbances, shows:

- Known areas which have been previously impacted by mining or exploration activities within the project area;
    - Including a total of 73 acres of previously disturbed area including roads, buildings, landing strips, electrical transmission lines, water wells, oil, and gas pipelines, and/or other surface and subsurface facilities within 200 feet of the proposed mining operations.

- The Planned Mine Disturbance; totaling approximately 28 acres of re-disturbance and new disturbance

Underground Mine Plan

Figure OP-3, Overall Mine Plan, shows the existing workings, existing wells, overall mine plan and ventilation holes. Most of the planned surface disturbances will be within the disturbance footprint of the existing mine permit.

Initial activities will focus on the dewatering of the Velvet decline. The water treatment area will encompass the same previously disturbed water treatment footprint and will utilize the same mine vent (Vent C) for installation of dewatering pump(s). It is assumed that approximately 50,000,000 gallons of water will need to be removed and treated initially. Mine water will be treated on site and discharged under a UPDES permit. Recent water sampling indicates the water contains 15.7 pCi/l combined radium-226 and radium-228, and 1.84 mg/l natural uranium with a pH of 8.3.

Table 1. Utah Water Discharge Standards

Parameter	CASRN	GWQS	Unit
Combined Radium-226 and Radium-228	7440-14-4	5	pCi/l
Gross alpha particle activity, including Radium-226 but excluding Radon and Uranium		15	pCi/l
pH		6.5-8.5	

Based on current Utah discharge standards (shown above) it is anticipated that mine water will need to be treated with barium chloride to remove the radium and with pH adjustment to remove uranium. Current testing indicates that the optimal treatment plan is mixing 0.03 g/L BaCl with mine water for 10-12 minutes, followed by a 40-minute settling time. This will take place initially in the pilot water plant constructed in the water treatment facility, which will be downsized after the first phase of dewatering is complete.

This treatment facility will be located directly above the historic mine water treatment ponds and will disturb a fraction of the previously disturbed area. Initial mine dewatering rates (6-month period) will be approximately 250 gallons per minute (gpm) to remove water stored in the mine. During this first phase of dewatering, a pilot treatment plant will be established, consisting of a 15,000 gallon mixing tank and two 40 cubic yard frac tanks for settling, at which point the treated water will be discharged. Once the initial mine dewatering is completed it is anticipated, based on historical records, that the rates to sustain the dewatering will be approximately 25 gpm. This, in conjunction with water from the frac tanks, will amount to approximately 16,500,000 gallons to be treated on an annual basis. At this time, the pilot treatment plant will be retired, and the permanent plant will be utilized. Water from mine dewatering will be used for non-potable needs at the mine site including dust control, sanitation, and underground drilling.

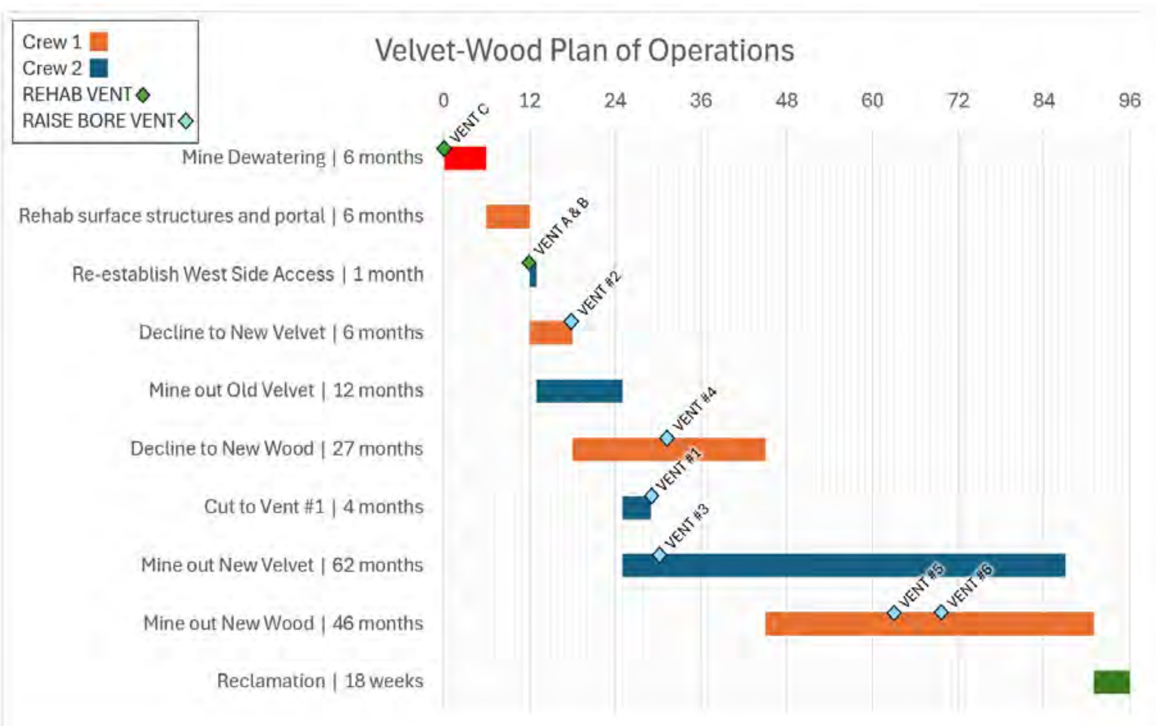
Precipitates from barium chloride treatment will be disposed of at an outside licensed facility. The barium chloride treatment will produce approximately 2.7 cubic yards of precipitate (20,350 pounds) in the initial mine dewatering. An additional 0.75 cubic yards (5,700 lbs) will be produced annually from mining activities. The precipitate is anticipated to have an activity level of 30,475 pCi/g.

Once the initial mine dewatering is completed, the focus will shift to rehabilitating the portal. As the water levels lower in the main decline, rehabilitation of the Old Velvet access will begin. The main decline system, shown on Figure OP-3, utilizes the original portal and decline to access the Old Velvet workings and remaining unmined reserves within that location. Vents A and B will be rehabilitated for use when work is proceeding in the Old Velvet portion of the mine. Two crews will be brought on to simultaneously rehabilitate and develop access to Old Velvet production areas and develop a new decline down to the New Velvet. The main decline extension will be constructed 12 feet wide and 9 feet high and will extend some 3,000 feet to the northeast from the portal. From the decline haulage mains, 12 feet wide and 8 feet high drifts will be driven to the three planned vent locations. The new vents will be established by up-reaming in the same manner as previously employed for existing vents. The new vents will be 72 inches in diameter or less. Once these aspects are in place, production can begin on the New and Old Velvet drifts.

The main decline extension will generate approximately 12,000 to 14,000 bank cubic yards of materials from non-mineralized stratigraphic units consisting of sandstone, shale, and clay from the Chinle and Mossback formations. This material, as well as that from the drifts being driven to the vents, will be utilized to create a shelf to expand the work pad (labelled in DET-1 as the Work Pad Expansion), on which the truck loadout area will be placed.

A decline from New Velvet will be developed to access the Wood mineralization. The Wood decline will be constructed at 12 feet wide and 9 feet high and will extend approximately 12,050 feet. The new vents will be established by up-reaming in the same manner as previously employed for existing vents. The new vents will be 72 inches in diameter or less. An additional water treatment plant will be placed near the Wood mineralization, with sustained dewatering rates of approximately 25 gpm. The following figure details the activities of the crews over the 8-year operating time from dewatering to revegetation.

Figure 1. Velvet-Wood Plan of Operations Chart



These timeframes are based on a mining rate of 7,345 tons material per month from the western/Old Velvet area; a mining rate of 6,585 tons material per month from the New Velvet area; and a mining rate of 6,930 tons/month from the New Wood area.

Production

The mine will be developed to ultimately support an average ore production rate of up to 500 tons per day, with an average waste to ore ratio of 0.2 tons of waste per ton of ore mined. Upon completion of main haulages and ventilation shafts, laterals will be driven along strike. The laterals will be driven through known ore-bearing zones to provide access for production mining. The laterals also provide access for geologic mapping, long-hole drilling, rib scanning and collecting samples. This geologic data will be used to develop detailed mine planning and stope development for each lateral. Mining will generally proceed from the laterals up dip, beginning at the farthest extents of the mine and retreating back to the main decline.

The ore will be mined using a modified room-and-pillar system and retreat mining. This mining method is common for mining in uranium-bearing sandstone and is designed to follow the irregular configuration of the individual ore bodies. Where possible, mined-out areas will be back-stowed with waste from adjacent mining. Once a room is fully mined and back-stowing is unpractical or unsafe, the roof will be collapsed to relieve stress on adjacent rooms and haulages.

The ore seams vary in height but average 6.7 feet or approximately equivalent to the full-face mining height of 7 feet. The minimum mining thickness, including dilution, is 4 feet. In instances with lower mine thicknesses, split shooting methods will be employed.

The mine will be operated using 2, 10-hour shifts and will consist of 2 mining crews and 1 utility crew. An additional crew will be available to rotate, totaling 3 shifts on an annual basis. Personnel requirements are summarized in the following table.

Table 2. Personnel Requirements

Hourly Labor Requirements	Per shift	Shifts/year	Total
Jumbo Miners	2	3	6
Jumbo Helper	2	3	6
Utility Miners (Const., Utilities, etc.)	1	3	3
UG Laborer	1	3	3
LHD Operators	1	3	3
UG Truck Operators	2	3	6
Surface Operators	1	3	3
Exploration Drillers	2	1	2
Electricians	1	3	3
Mechanics	1	3	3
Control Room Operator (Dispatcher)	1	3	3
Warehouse Laborer	1	3	3
Total Hourly	**16**		**44**
Salaried Personnel Requirements	Per shift	Shifts/year	Total
Manager/ Chief Engineer	1	1	1
Mine Foreman	1	1	1
Foreman/Shifter	1	3	3
Engineers and surveyors	2	1	2
Chief Geologist	1	1	1
Geologists	1	3	3
Safety Manager/ Personnel Manager	1	1	1
Maintenance Supt.	1	1	1
Technicians	2	1	2
Accountants – Clerk	1	1	1
Purchasing Agent	1	1	1
Total Salary	**13**		**18**
Total Annual Personnel	**29**		**76**

The anticipated equipment list for the underground operations is presented in the following table.

Table 3. Preliminary Mine Equipment List

Equipment Requirements	Quantity
Development Jumbo - single boom	2
Drifter, Hydraulic	3
Drifter Feeds	3
Jackleg drills w/ legs	4
Compressor 350 cfm	2
LHD 2 cy	2
Trucks 10 ton	3
Cat 973C track loader/dozer	1
Pumps	4
ANFO Loaders	3
Service Vehicles	1
Scissor Lift Truck	1
Main Ventilation Fans 63”	6
Electric Motor 350 HP	6
Accessories for 63” Fan	6
Auxiliary Fans 14000 cfm (each drill needs 3 faces)	15
Exploration Drills	2
Water Truck 4,000 gallons	1
Refuge Chambers	2
Safety Equipment	1
Portable Power Center 150 Kva	4

Jumbo drills operating on compressed air will be utilized to drill the blast holes and rock-bolt holes in the declines and laterals. Air-jacklegs will be utilized in production areas. All blasting operations will be conducted in accordance with MSHA regulations (30 CFR Parts 56 and 57). Blast holes will be loaded with an electric blasting cap, chemical booster, and a mixture of ammonium nitrate and fuel oil (ANFO) prills. The blasts will be initiated electronically with the hole pattern, firing sequence and delays designed to allow for optimum breakage. Explosives and detonators will be stored in underground magazines and transported from the magazines to the working face in accordance with MSHA regulations (30 CFR Part 56 and 27 CFR Part 55).

The ore and waste rock will be mucked out using 2 cubic yard low-profile diesel loaders (LHD’s). Ore will be hauled to the surface ore stockpile toe using low-profile diesel haul trucks with capacities of ten tons. During initial decline and lateral development, the unclassified waste rock will be hauled to the surface and placed in the work pad expansion area. Waste produced during subsequent development and production will be disposed of both on the surface and underground in mined out areas whenever possible to minimize waste rock volumes at the surface. Backstowing will be used preferentially, and waste will only be disposed of on the surface if ground conditions (such as unstable workings) prevent underground disposal. It is anticipated that at minimum 60% of mined waste will be able to be backstowed. The surface waste stockpiles are capable of accommodating approximately 40% of the maximum production of waste rock over the life of the mine; the reclamation surface can accommodate approximately 50% if necessary.

Roof support will consist of metal roof mats anchored into the roof using eight-foot-long resin roof bolts. Bolting will be performed as necessary with the spacing varying according to roof conditions and the size of the opening. The size of the mine openings will depend on roof conditions but will typically be 14-feet or less in width based on the experience of similar mining operations conducted in the same formation. Ten-foot-long mats will be installed diagonally on the ribs when additional rib support is required. The underground area will also include maintenance and storage areas. Routine maintenance and minor repairs will generally be done underground with more extensive repairs and maintenance completed in the surface shop. Roof support materials, blasting supplies, lubricants and the smaller and more commonly used equipment parts will be stored in designated locations underground. These locations are expected to change as the mine workings are advanced.

Mined Material Handling

Based on the available data, recommended clean-up criteria, and applicable standards and/or criteria, mine spoil has been subdivided into the following categories:

- **Interburden/unclassified waste rock** - Material which is radiometrically equivalent to background, is not acid forming, and does not contain concentrations of metals or other constituents in excess of DOGM criteria. This material can be used for most construction purposes and will be used to form the work surface on the work wad expansion area. It may additionally be stowed in the surface waste rock area or underground. This material will be produced from development headings including the main declines.
- **Subgrade ore/mineralized waste rock** - Material which contains at least 0.03 weight percent U_3O_8 but is not economically retrievable. This material is slightly elevated in radionuclides, less than 10 pCi/g radium-226, and may have the potential to be acid forming and/or contain metals in excess of DOGM criteria. During operation, this material will be stockpiled in mined-out areas away from the groundwater table, but in such a manner that it may be retrieved should it become economically viable over the course of operations. At the conclusion of operations, the material will be backstowed. This will occur either above the groundwater table or deep enough below the groundwater table to be reasonably expected to be anoxic. In either case, the metals and radionuclides will be rendered immobile. If backstowing is not possible, then it will be placed in the center of the surface waste rock pile beneath a minimum of 10 feet of interburden waste cover upon mine closure.
- **Ore** - Material which contains above currently economically retrievable grades of uranium/vanadium mineral. This material will be brought to the surface and stowed in the ore stockpile bins before being hauled offsite to the Shootaring Canyon Uranium Facility. In the event of an economic downturn in the uranium market, ore may become subgrade. In this case, the subgrade material will be backstowed above the groundwater table into the existing underground workings or buried in the waste rock final reclamation surface at a depth equal to or greater than 10 feet.

The majority of material will be sourced from the upper and lower Chinle formations, which is not anticipated to be acid-generating.

Surface Facilities
The proposed surface facilities are shown on Figure DET-1, Velvet Surface Facilities. In no case will any surface facilities or stockpile areas be located above the decline to the mine. These facilities include the following:

- Waste rock pile
- Ore stockpile and truck loadout area
- Topsoil stockpile areas
- Storm water/surface drainage control structures
- Fuel and oil storage areas
- Office & Employee Facility
- Maintenance shop & warehouse
- Designated parking and lay down areas
- Mine access roads
- Air compressor
- Mine Vents
- Water Supply System
- Fenced leach field
- Solid waste storage (trash, scrap metal, batteries)
- Propane tank

Mine dewatering, treatment and discharge facilities are discussed in and includes:

- Dewatering vent
- Waterline corridor
- Water treatment facility
- Access roads

Surface support equipment will be limited and will include:

- Light vehicles for the maintenance, engineering, and safety departments.
- ATV's for use in areas with limited access and/or during inclement weather conditions.
- One track loader/dozer for use dressing stockpiles and loading ore.
- Ore will be transported from the site using commercial over the road trucks with pup trailers and approved covers. A typical haul truck, trailer, and 2-axle pup will have a tare weight of approximately 47,500 pounds and a gross vehicle weight of approximately 124,000 pounds.

Figure OP-3, Overall Mine Plan, shows existing and proposed ventilation shafts. Access to the mine portal will utilize the existing haul road from the county road which passes through the area. Access to the mine vents and dewatering facility will utilize existing access and/or exploration drill roads.

Minor changes may be made to the proposed layouts during construction with BLM and DOGM approval; however, construction activities, unless otherwise noted, will be confined to the previously disturbed and reclaimed areas of the project site.

Waste Rock Pile – Where possible, waste rock will be disposed of underground. However, when brought to the surface, waste rock storage will be restricted to the existing disturbance footprint as shown on Figure DET-1, Velvet Surface Facilities. A total volume of 147,000 in-situ cubic yards of unclassified and mineralized waste rock will be generated over the life of the mine. Applying an average swelling factor of 30% to that total means that a total of up to 191,000 cubic yards of unclassified and mineralized waste rock is anticipated based on the detailed mine schedule. As shown on Figure DET-1, the operational design capacity is 74,000 cubic yards of material including the waste rock pile and work pad expansion. The final reclamation capacity of the disturbance footprint can accommodate a total of 75,000-115,000 cubic yards of waste rock. This is due to the ability to adjust the contours of the final design to match the actual production of waste rock from the mine. As such, raising or lowering the final contour designs 5ft or less can adjust up to +/- 40,000 cubic yards while staying within the disturbance footprint and final slope gradients.

The general configuration of the waste rock pile is planned to slope upward from the portal at a 15% grade, which is slightly flatter than the 17% decline grade. The waste dump will be constructed in lifts, beginning with the maximum overall footprint. Side dumping underground 10-ton mine trucks will exit the portal, and run a right-handed traffic pattern, dumping each lift from the east edge to the west. Following completion of each lift, it will be leveled, and the next lift begun until the pile is completed. The maximum stockpile height will be 40 feet or less. Waste rock will be placed at slopes of 1.5 H:1V or less for operational conditions and will be regraded to lesser slopes for reclamation. Waste rock will be segregated based on quality and/or character. Waste from the decline extension is expected to be clean interburden material consisting of sandstone, shale, and clay. This material will be segregated for use in constructing an expansion to the work platform. Waste from the ore bearing horizon will be separated into subgrade ore (material falling below current economic cutoff but containing more than 0.03 weight percent U_3O_8) and unclassified waste rock, with subgrade ore being preferentially stowed underground for potential retrieval in the case that economic conditions allow for processing. If this is not the case, the material will be treated as mineralized waste rock at the time of reclamation and isolated and buried in the waste rock area. The unclassified waste rock will be backstowed wherever possible, and hauled to the waste rock area on the surface where not. The waste rock pile will be covered with the clean interburden material used to construct the work pad expansion prior to application of available topsoil and revegetation. The total area of waste rock storage is planned to be approximately 2.5 acres. See the subheading “Mined Material Handling” on page 14 above for information on waste rock characterization.

<u>Ore Stockpile and Truck Loadout Area</u> – Ore will be stockpiled adjacent to the main decline on top of the historical mine waste rock area and contained within a concrete ore bin, refer to Figure DET-1, Velvet Surface Facilities. The location of the ore loading station is labeled Truck Loadout Area as shown in Figure DET-1. Mined ore will be transported from the site for processing shortly following mining. It is anticipated that no more than 2 months’ worth of ore (24,000 tons) will be present in stockpile at any given time and that the ore stockpile area will not exceed one acre in surface extent. Ores will be continuously trucked from the site to the Shootaring Canyon Uranium Facility near Ticaboo, Utah. In the event that the Shootaring Mill is unavailable, ore will instead be hauled to the Energy Fuels Blanding Mill.

<u>Topsoil Stockpile Areas</u> – The mine area was disturbed by historic mining and exploration activities that occurred prior to the implementation of state and federal reclamation laws. As a result, little topsoil was salvaged prior to initial mine development and the majority of the mine

site was later reclaimed using the soils and unclassified waste rock that existed on the disturbed areas at the time of reclamation. Available topsoil will be salvaged from all excavation areas including reclaimed areas, provided that the topsoil has not been degraded by historic mine wastes. Topsoil will be tested for baseline properties prior to stockpiling. All topsoil stockpiles will be neatly dressed and identified with signage clearly identifying the stockpile as topsoil. The topsoil stockpiles will be limited to no more than 16 feet in height and equipment travel over the piles will be prevented so that compaction is minimized. The stockpile locations are placed to minimize contributing drainage areas and erosion losses and are uphill from the fueling station.

The topsoil stockpiles will be contoured, furrowed, and broadcast seeded with the seed mixture presented in Attachment F, Reclamation Plan and Bond Estimates, in the soonest late fall season once the stockpiles are at their ultimate configuration. Reasonable efforts and management practices will be used to minimize topsoil erosion from the stockpile areas. If excessive erosion is observed during regular monitoring, silt fences and\or snow fencing may be placed around the perimeter and on the surface of the stockpiles to mitigate soil loss. Prior to being removed from the stockpile for reclamation, topsoil will be re-tested and amended as needed.

Storm Water/Surface Drainage Control Structures – No disturbances to existing drainage systems are planned or proposed. Surface facilities will be contained within existing disturbance areas which are located outside of the ephemeral drainages in the mine area. All storm water runoff contacting the ore stockpiles, waste rock stockpiles, and other disturbed areas will be routed to storm water catchment ponds sized to contain 10-year 24-hour precipitation events. This contact storm water from the mine portal area will be transported by water truck to the mine dewatering treatment area for treatment and subsequent discharge under a UPDES permit. Some of the treated water may be trucked to a storage tank located near the employee facility and workshop to provide non-potable water to these facilities (Figure DET-1). Non-contact storm water up gradient of the facilities will be routed away and\or around the mine facilities.

The historical mine water treatment area, located adjacent to the unnamed drainage to the southeast of the portal (see Figure OP-5), will be used for the new mine water treatment facility. Construction disturbance will be limited to the northern margins of the area to avoid impacting drainage. Silt fencing will be utilized to limit migration of sediment. Temporary diversion structures will accommodate the runoff generated from over 98 percent of the storms expected during the potential mine life and will be maintained by the mine operator as needed. As best management for implementation of the UPDES permit, sediment control measures including undisturbed buffer areas, stormwater catchment ponds, earthen berms, and/or sediment control fences will also be placed down gradient from disturbed areas to minimize the volume of sediment impacting the drainage system.

Fuel and Oil Storage Areas – Diesel fuel and other petroleum products will be stored on-site in tanks, drums, and smaller containers. The fuel storage area is shown on Figure DET-1, Velvet Surface Facilities. The fuel storage containment area will be surrounded with earthen berms and covered with a synthetic HDPE or equivalent liner to contain any fuel spills or leaks. The synthetic liner will be covered with a protective layer of road base. The berms will be established at the height necessary to contain the total volume of the largest tank within the containment area plus an additional ten percent. The fueling areas will be sloped so that any spills during equipment fueling or fuel delivery to the site will flow into the containment area, which will be able to contain the total volume held within the berm plus an additional ten percent.

Diesel fuel will be stored in two 10,000-gallon tanks which will be painted a neutral color. The mine will use an estimated 1,500 gallons of diesel per day. Approximately 10,000 gallons of diesel will be kept on-hand; therefore, 10,000 gallons of diesel will be delivered every 5-7 days.

In the interest of reducing emissions, connecting the facility to line power will be pursued in the long term and an amendment for the power line disturbance made at that time. For the immediate term, diesel generators will be utilized. A 20’ by 50’ concrete pad will be installed to support electrical utilities, upon which up to 4 generators will be placed. A generator type like the Volvo Triton Tier 4 Final diesel generator will be used for this purpose, with the following specifications:

Table 4. Generator Specifications

Model	TWD1673GE
Engine Speed	1800 RPM
Engine Power Output at Rated RPM	655 kWm/878 HP
Cooling	Radiator cooled
Fuel Consumption (Full Load)	128.9 L/hr
Fuel Consumption (75% Load)	97.7 L/hr
Fuel Consumption (50% Load)	67.8 L/hr

Mine Office – A 48’x60’x8’ building will be used to house the mine office and employee facility. It will be a prefabricated metal building with a 6-inch slab on grade foundation. The location of the office along the access road serves a separate function of providing site access control to limit public access. Figure DET-1 shows the location of the mine office. Vendors and site visitors can be stopped with signage and a gate, directed to the office, and provided with site specific safety training prior to entering the site. The building will be painted neutral colors to better blend in with the surrounding natural features. Upon completion of mining, the facility will be removed from the site.

Employee Facility– The employee facility will be in the same building as the mine office. Employee parking will be located on an existing small disturbance on the east side of the main access road. The employee facility will include a lunch/meeting area, toilet and shower facilities, and laundry area. Non-potable water will be supplied from the mine water treatment system effluent released under UPDES permit UT0025810. Treated water will be trucked from the treatment area to a holding tank (see Figure DET-1). Black and gray water from onsite facilities will be pumped to the leach field to be treated. Potable water will be provided from an approved commercial source.

Maintenance Shop and Warehouse – A 40’x80’ shop and warehouse with attached wash bay will be constructed as shown on Figure DET-1. These facilities will consist of prefabricated metal buildings on 6-inch concrete slab on grade foundations and will be painted neutral colors to blend in with the surrounding natural features. All drainage from the shop floor and wash facility will be collected for reuse and/or treatment and disposal. This will include a lined sump and oil water separator, with water pumped to storm water drainage control structures for treatment. Oil wastes from a separator will be contained in drums on palettes and removed by a qualified third-party vendor for recycling. Waste oil and other petroleum-based products will be collected for recycling by a qualified vendor. Upon completion of mining these buildings will be removed from the site. Concrete pads will be demolished, and the waste concrete used for bulkhead material in the closure of the mine decline and/or disposed of at a licensed landfill.

Designated Parking and Lay Down Areas – Designated parking and laydown areas are shown on Figure DET-1. These areas will not be paved but will be graveled utilizing clean interburden waste materials from the decline extension.

Mine Access Roads– The primary road into the site is a county road that continues past the mine.

Air Compressor– An air compressor will be located on the south end of the shop. The air compressor will be used to supply compressed air for pneumatic drills and other equipment both on the surface and underground.

Mine Vents - As shown on Figure OP-3, nine mine vents are planned: one pre-existing for dewatering and two pre-existing for ventilation; and six newly constructed for ventilation. Mine ventilation will be of sufficient volume to maintain radon, exhaust, and other fumes and gases to safe working levels as required by MSHA. It is anticipated that this will require the movement of 200,000 CFM of air through the mine. Each vent will have a maximum of 14 ft wide by 14 ft long and 8-inch-thick concrete slab base.

Vent 4 will be equipped with 8ft long, 8ft wide and 6ft high emergency escapeway shack that will sit on a larger vent pad than the typical 14ftx14ft. Rather, the emergency escapeway and the vent will occupy an 8-inch concrete pad up to 24ft long by 14 ft wide. One vent out of vents A, B, C and 1, 2, 3 will be equipped with an emergency escape way for the Velvet side of the complex. One vent out of vents 5 and 6 will be equipped with an emergency escape way for the Wood side of the complex.

Water Supply System – Water for bathrooms, showers, washing equipment, and other general uses will be supplied by recycling the treated mine water. The treated water will be pumped from the mine dewatering water treatment facility to an elevated tank, from which water will flow by gravity to the surface facilities. The pipeline will follow existing roads, and the tank pad will be placed on a previously disturbed area as shown on Figure DET-1. The treated water is not potable, and drinking water will be supplied by the mine from an approved commercial source.

Fenced Leach Field – An industrial septic tank and leach field utilizing high-capacity leaching chambers in a mounded system will be located down gradient from the site and fenced to prevent mine traffic from travel on the leaching chambers. The septic system will be designed and installed to meet current state and local regulations. The septic system will be pumped out, as needed, on a routine basis. See DET-1

Solid Waste Storage – A roll off container for disposal of trash will be located next to the Maintenance Shop and Warehouse. The trash will be picked up on a routine basis by a service company and disposed of at an approved landfill. No landfills will be constructed on site. Scrap metal will be stored in a bin and/or on pallets near the Maintenance Shop and Warehouse until it can be picked up for recycling. Used batteries and tires will be stored in the same area and will be picked up and recycled by vendors. See DET-1.

Propane Tank– Propane will be used to heat buildings. The tank will be located in a fenced area near the buildings. The propane will be stored in a 2,000-gallon tank and will need refilled 2 to 3 times per year depending on the shop and office demands. See DET-1.

Water Treatment Systems – Water treatment facilities are described in detail in Figures DET-2 and DET-3. The Velvet facility will be constructed within the previously existing disturbance area of the historical water treatment area and will be fenced to prevent intrusion by livestock. The Wood facility will be located adjacent to existing road disturbances. Liquid effluent will be discharged at the velvet facility under UPDES permit UT0025810. All solid water treatment wastes will be characterized and disposed of in an appropriate offsite permitted disposal facility to be determined based on the solid waste characteristics. Upon completion of mining, the water treatment systems will be removed. Any contaminated soils or materials, including the synthetic liner, will be transported off site for permanent disposal at a duly permitted facility.

Waterline Corridor – Water will be pumped from the mine workings via Vent C, shown on Figure OP-5. The water will be pumped through a nominal 6-inch schedule 80 HDPE line following the same route as historically utilized for mine dewatering. This line will be installed on the surface and covered with at least 42 inches of soil to prevent potential freezing during cold weather.

Powder Magazine – Details are confidential. See Attachment N.

Temporary Closure

In the event that market conditions or other circumstances require a temporary cessation of mine operations, Anfield Energy, Inc will provide notice to the BLM in accordance with requirements of Part 3802.4.7, Title 43 of the Code of Federal Regulations (CFR) and to DOGM in accordance with Utah Rule R647-4-117. The Interim Management Plan is described in detail in Attachment L.

106.3 - Estimated Acreages Disturbed

The complete mine disturbance area is compared to the previously disturbed areas that are included in the current mine permit as shown on Figure OP-2. The total area to be disturbed by the proposed mine permit, including both areas that were previously disturbed and undisturbed ground, is approximately 28 acres. A breakdown of the disturbance areas and their bond release status is given in Table 5 below and on Figure OP-5 Overall Surface Facility Map.

Table 5. Mine Disturbance Acres

AREA	MINE ACRES	PREVIOUSLY DISTURBED ACRES
VELVET SURFACE FACILITIES	11.4	9.2
VELVET WATER TREATMENT PLANT	1.9	1.7
WOOD WATER TREATMENT PLANT	0.5	0
ROADS	14.2	60.36
VENTS A,B,C	0.01	1.7
VENTS 1,2,3,4,5,6	0.02	0.04
TOTAL	28.02	73.00

106.4 - Nature of Materials Mined, Waste, & Estimated Tonnage

Thickness of overburden:	800 to 1,500 ft.
Thickness of mineral deposit:	Avg. of 6 ft.
Estimated annual volume of waste rock:	11,000 to 28,000 cu.yds.
Estimated annual volume of tailings/reject materials:	0 cu.yds.
Estimated annual volume of ore mined:	31,000 to 100,000 cu.yds.

Interburden waste rock will be generated from the development of a new decline to access the ore in Section 2 and from mined inter-burden from the ore zone. The interburden waste rock is comprised of a fine to very coarse-grained quartz, feldspar, lithic, arkosic sandstone. Based on field observations of the existing reclaimed waste rock area, the waste is not acid-generating, nor does it contain mineral concentrations that are toxic to vegetation. The interburden waste rock originates from the unconformity between the Cutler Formation and the Moss Back Member of the Chinle Formation. The blasted arkosic sandstone waste will range in size from fine-grained sand to a maximum of two feet in diameter.

Note: The estimated 31,000 to 100,000 cubic yards of ore is based on escalating mining rates and waste-to-ore ratio over the course of production. Production rates are estimated to start at approximately 60,000 tons per year during decline and lateral development based on the detailed mine schedule utilizing two crews working 10-hour shifts daily. During this time, an average waste to ore ratio of 1/1 is expected with a density of 100 lbs/ft^3, producing approximately 31,000 cubic yards of ore. During later production, after declines are completed and the mine has expanded, the production rate is expected to increase to approximately 120,000 tons per year. The waste to ore ratio is expected to decrease significantly during later production (i.e., 0.5 or lower) resulting in the generation of proportionately less waste as full production is reached, allowing for ore production around 100,000 cubic yards. An ore stockpile density of 90 pounds per cubic foot (lbs/ft^3) was used to convert tonnage to cubic yards and is inclusive of an approximate average swell of 50% from in-situ to stockpile.

106.5 - Existing Soil Types, Locations, & Amount

A baseline soil resources assessment update was conducted for the Velvet-Wood project area and is included as Attachment B to this NOI/POO. Field data collection was not conducted with an approach consistent with a Soil Order III baseline soil survey necessary to meet requirements of Rules R647-4-106.5, 106.6, and 109.3 of the Utah Administrative Code but was meant to update the existing resources assessment for the Mine area. The survey is described in detail in Attachment B. The objectives of the soil resources assessment were to:

- Survey and document soil map units in the project area;
- Establish soil reference areas.

The soil survey was conducted concurrently with vegetation resource surveys (see Attachment B). Vegetation surveys were accomplished on foot and focused on disturbed and undisturbed portions of the site.

The project area includes four major soil map units, as determined by the U.S. Department of Agriculture, Soil Conservation Service (USDA SCS): Rock outcrop-Rizno complex, Rizno-Rock outcrop complex, Begay fine sandy loam and Bond-Rizno fine sandy loam (see soil map in Attachment B). These broad soil map units are defined as unique natural landscapes and may consist of one or more major and/or minor taxonomic soil classifications. Soil map units are based on landscape-scale similarities observed in parent material, general soil characteristics, elevation, precipitation, position within the landscape, and vegetation, among others. Finer variations in these parameters further define these broad map units into a mosaic of taxonomic classifications.

The project area has been impacted extensively by past mining and exploration activities, both historic and more recent. Mining activity has resulted in the creation of soil types that are different in character from the surrounding mapped units. These mining-related soil types include the rock waste rock pile located in the portal area. These rock and clay soils were reclaimed in-place by the previous mine operator without benefit of native topsoil. The waste rock pile and the water treatment area will be re-disturbed by the proposed project. These areas are shown on Figure OP-5.

The four major soil units identified will not be impacted by proposed mining operations. Detailed information on these soil units is provided in Attachment B. The portal area is located within the Mining-Related soils unit.

<u>Rizno Series</u>
The Rizno series consists of very shallow and shallow, well drained soils that formed in residuum, colluvium, and eolian material derived from sandstone, siltstone, and limestone. Rizno soils are on structural benches on cuestas, mesas, and ridges. Slopes range from 2 to 60 percent. The mean annual precipitation is about 11 inches, and the mean annual temperature is about 51 degrees F. This soil can be found at elevation of 4,000 to 8,000 feet AMSL. Vegetation on this series generally consists of blackbrush, Mormon-tea, Utah juniper and pinyon. This soil is used mainly for rangeland and can be found throughout Southeast Utah, northern Arizona, Western Colorado, and

northwest New Mexico. This series is of substantial extent. The Rizno-Rock outcrop complex represents the primary soil resource within the general portal area.

Begay Series

The Begay series consists of very deep, well drained, moderately rapidly permeable soils that formed in eolian deposits and alluvium, derived mainly from sandstone. Begay soils are on structural benches, broad mesas, fan remnants and have slopes of 0 to 30 percent. The mean annual precipitation is about 12 inches, and the mean annual temperature is about 48 degrees F. Elevation for this soil ranges from 4,700 to 7,400 feet AMSL. Typical vegetation found on this soil consists of needle and thread, big sagebrush, blue grama, and Indian ricegrass. This soil is used only as rangeland and is associated with semidesert regions throughout southeastern Utah and northwestern Colorado. Begay soils are moderately extensive.

Bond Series

The Bond series consists of very shallow and shallow, well drained, moderately permeable soils that formed in alluvium, slope alluvium, and eolian deposits derived from sandstone on cuestas, mesas, hills, and ridges. Slopes range from 0 to 50 percent. The mean annual precipitation is about 11 inches, and the mean annual temperature is about 51 degrees F. This soil can be found at elevations ranging from 5,600 to 7,200 feet ASL. The present vegetation is blue grama, sideoats grama, New Mexico feather grass, Indian ricegrass, scattered one seed juniper, and winter fat. The major use of this soil is for livestock grazing. The series is of moderate extent and can be found throughout west-central New Mexico, northern Arizona, southwestern Colorado, and southern Utah.

Mining-Related Soil Units

Soils located in the immediate vicinity of the mine portal consist of a pink, gray and white, sandy unclassified waste rock. The area is situated above a narrowing floodplain/canyon bottom that was not disturbed by previous mining operations. Samples will be taken in this location to evaluate the physical and chemical soils properties of the waste rock pile. The reclaimed evaporation pond is predominantly made up of local material and rock from the initial leveling of the pad. These soils are rocky and thin but support limited vegetation.

Soil samples will be collected for laboratory analysis from the soil map units that will be impacted by mining operations. Samples will also be collected from the reclaimed waste rock area, ore stockpiles, and the evaporation pond area. Field parameters will include location and thickness and any structures that have developed. Laboratory parameters analyzed will include pH, electrical conductivity, calcium, magnesium, sodium, potassium, soil adsorption ratio, cation exchange capacity, percent organic matter, total nitrogen, available nitrate, phosphorus, and potassium, composition of sand, silt, and clay, texture, percent coarse fragments, percent total sulfur, neutralization potential and acid/base potential.

106.6 - Plan for Protecting & Re-depositing Soils

Soils Available for Salvage and Potential Salvageable Quantities

The primary areas that will be disturbed within the project area are the surface facilities and portal area.

Figure OP-4 presents the topsoil stripping estimates for the portal area and nearby surface facilities.

As shown, the southern and northern portions of the proposed disturbed portal area has between 2 and 6 inches of strippable soil and the central portion has between 0 and 5 inches of strippable soils. Most of these soils are of the past revegetation of the waste rock areas. The revegetated waste rock material from previous mining (the central portal area) is marked as a Potential Topsoil Strip Area in Figure OP-4. It is not as good a resource as the native soils; however, it does support vegetation, as evidenced by the limited revegetation success to date. Soil depths of 2.5 inches and 6 inches are assumed in the central portal disturbance and the remaining portal disturbance respectively. A soil depth of 6 inches is also assumed in the nearby surface facility area to the north. All stripping will result in a total of 2,190 bank cubic yards (byc) of soil. Topsoil will not be stripped from buffer areas next to the drainages, the leach field, or the topsoil stockpile areas. Soil stripping efficiencies will also be relatively low in those areas where the soil is thinner or intermixed with gravel and rock. The stripped soils will be placed in a topsoil stockpile for the portal area and windrowed for the facility area to the north (see Figure OP-4). The stockpile height was driven by land area limitations. The topsoil stockpile will have a maximum height of about 16 feet and an average height of 8 feet due to land area limitations. A total of approximately 1,030 cubic yards of topsoil will be stripped from the two water treatment areas and windrowed to the side. See Figures DET-2 and DET-3 for locations of topsoil windrows.

<u>Topsoil Stockpiles</u>
Most soil stripping will be performed using a tracked dozer, although a front-end loader and/or motor grader may also be used. Stockpiles will range from 8 to 16 feet in depth. Equipment will not be allowed to cross over the piles so that compaction is minimized. The topsoil pile locations shown on Figure OP-4 were placed outside of drainage areas to minimize erosion losses.

Topsoil piles will be contoured, furrowed, and broadcast seeded in late fall with the following approved seed mix:

Topsoil Stockpiles Seed Mix		
Common Name	Species Name	Rate lbs/ac (PLS)
Thickspike wheatgrass	Elymus lanceolatus	3.0
Slender wheatgrass	Elymus trachycaulus	3.0
Crested wheatgrass	Agropyron cristatum	2.0
Yellow sweet clover	Melilotus officinalis	0.5

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In the event that vegetation is difficult to establish, the stockpiles will be blended to match the surrounding terrain as much as possible. Please refer to Section 110.5 for specific revegetation methods that will be used. Sediment controls (i.e., grass buffer areas, earthen berms, straw bales, etc.) will be installed and maintained as necessary, to prevent surface run-off from mine operational areas and roads from intersecting the topsoil piles within the surface facilities area. Vegetation success on the stockpiles will be monitored and stockpiles will be reseeded where vegetation is sparse.

Anfield will sample sediments from storm water control structures following mining activities. These samples will be analyzed for metals and radionuclides, as well as sulfates and selenium. Based on the results of the sediment analysis following mining activities and their comparison to baseline conditions at the pond site, Anfield will remove contaminated sediments and bury them with the mineralized waste material in the waste rock pile. This commitment will eliminate concerns about contaminated sediments being left behind and their potential to become airborne.

106.7- Existing Vegetative Communities to Establish Revegetation Success

The project area is dominated by pinyon-juniper woodland, sagebrush shrubland, mixed bedrock canyonlands, and disturbed plant communities. There are no wetlands or perennial streams present within the Velvet-Wood project area. Although the national wetland inventory displays two wetland areas with the code PUBFx in the area of the dewatering ponds, this is historic data that is not reflective of current conditions. The wetlands in the area were mapped using 1986 imagery when man-made settling ponds established for the previous mine were no longer in use but were still present. These ponds and their outlets were reclaimed after 1986 and no longer exist. A small stretch of land between the ponds is marked as permanently flooded, but this was only true when the ponds were present and used to discharge mine water. This no longer the case. Remaining streambeds in the area are intermittently flooded, not perennial streams. In the area of the Wood project a few very small intermittently or seasonally flooded wetlands are mapped. However, these wetlands are outside of proposed disturbance areas.

Of the 105 BLM Sensitive species for Utah, 12 species are listed as being potentially present or have been found on lands in San Juan County, Utah. See Table C1 in Attachment B. Four of these species have potential to occur within the project area. None of the other eight rare plants listed for San Juan County are known from or have habitat within the project area.

NCRS ecological site descriptions (ESD) were obtained for the area of the Velvet Wood surface facilities, the Velvet water treatment area, and the Wood water treatment area. NRCS mapping classifies the Velvet Wood surface facilities area and the Velvet water treatment area as Upland Shallow Loam, and the Wood water treatment area as Upland Stony Loam and Talus Slope. See Appendix B for full ESD descriptions taken from the NRCS.

The Upland Shallow Loam ESD, covering the Velvet Wood surface facilities and the Velvet water treatment areas, gives a percent coverage for grasses, shrubs, and forbs of 2-21%. The following images were taken on undisturbed ground north of the disturbance where the surface facilities will be located.

The following images were taken on undisturbed ground north of the disturbance where the Velvet water treatment facilities will be located.

The area around the Wood water treatment plant in the NCRS mapping includes both the Upland Stony Loam and the Talus Slope ESDs. The Upland Stony Loam ESD describes two types of communities, one with pinyon and juniper trees and perennial grasses in the understory and one dominated by pinion and juniper trees. The first community in the ESD has a plant density without trees of 4-18% and the second a density of 0-15%. The Talus Slope ESD occurs on talus slopes, escarpments, landslides, steep hillslopes, steep mountain slopes, and ledges. The plant density given excluding trees is 67-73%. The majority of the area around the planned treatment plant is in line with the Upland Stony Loam ESD, not the Talus slope ESD. The following images were taken near the area to be disturbed for the Wood water treatment plant. The images given below appear to show both types of Upland Stony Loam communities.


5/18/23, 8:27:05 AM
UTM 665695 4220106
234 deg(T) 2010 m
ACCURACY 5 m
DATUM NAD83
Velvet Mine
RockyPJ
EastEntranceRd

An approximate average value of the ranges given in the Upland Shallow Loam and Upland Stony Loam ESDs and in line with the images would be 10% ground cover. Although the Talus Slope has a much higher plant coverage in the ESD, its occurrence is low compared to the other communities. In light of this, it will be weighed much less in an overall plant coverage value to be used for pre-disturbance vegetative coverage. A value of 15% coverage prior to disturbance will be used in order to gauge revegetation success.

106.8 - Depth to Groundwater, Extent of Overburden, & Geologic Setting

Updated surveys have been conducted though reports have not been compiled and received.

Depth to groundwater: Approximately 400 ft.

Two site ground water monitoring wells (CL-34T-08A and V-6-08B) have been installed (Figure OP-2) and water level measurements have been collected from the upper and lower vent shafts. The uppermost aquifer was encountered near the contact of the Moss Back Member of the Chinle Formation and the uppermost sandstone in the Cutler Formation. Based on the depth of the Moss

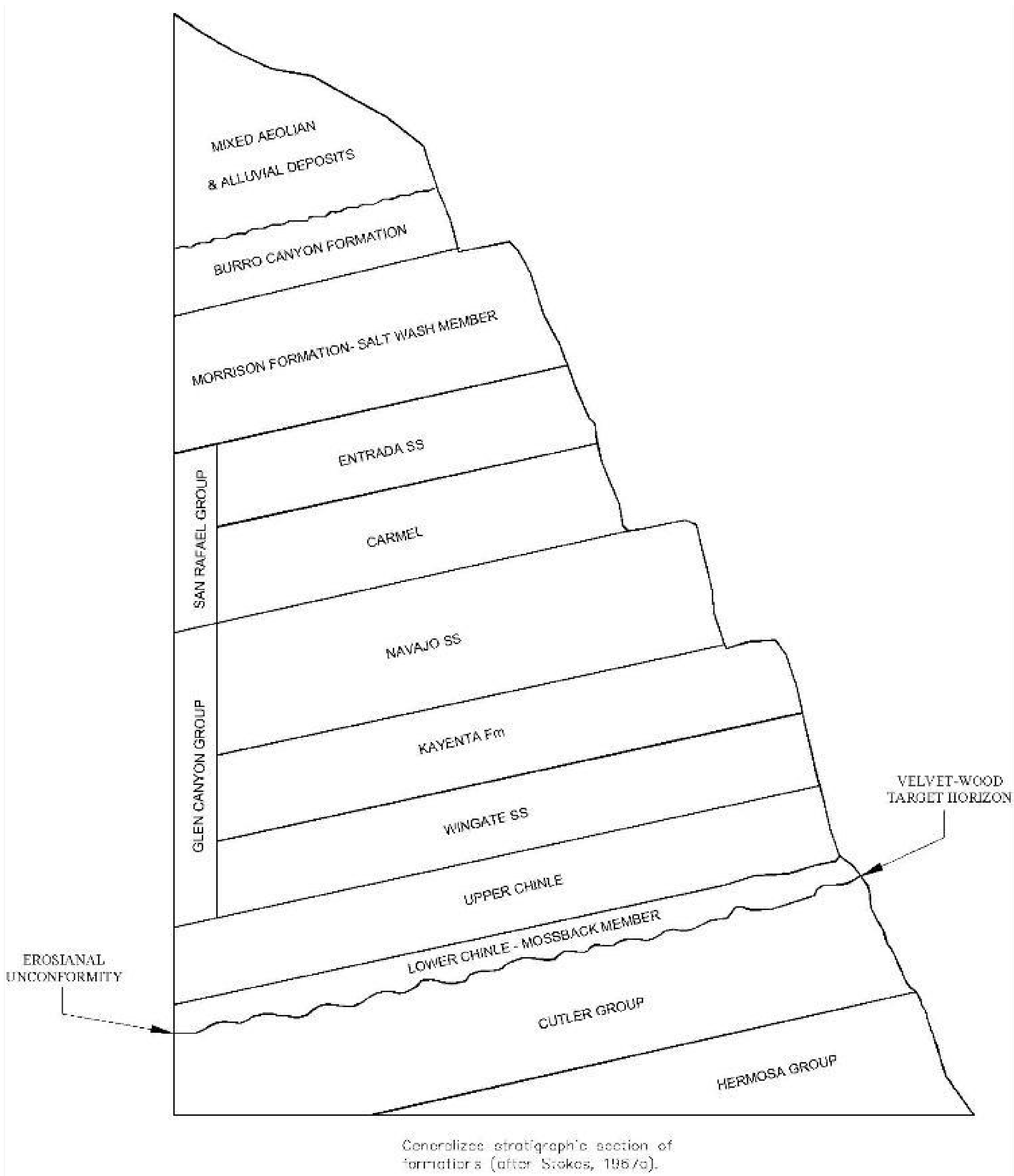
Back Member and the measured water levels, water within the Moss Back Member is confined. A summary of the construction details of the existing monitoring wells and ground water depths and elevations is provided in Table 6. A hydrogeology report is included in Attachment C as part of the submittal for approval to implement a pilot treatment system during initial mine dewatering.

Table 6. Summary of Existing Monitor Well Construction and Static Water Levels

Monitor Well ID	Total Depth, ft bgs	Screened Interval, ft	Collar Elevation, ft asl	Depth to Water, ft bgs	Groundwater Elevation, ft asl	Mossback Mbr Upper Contact Elevation ft asl
CL-34T08A	840	736 to 836	6649.20	395.0	6254.2	5871.0
V-06-08A	980	880 to 980	6648.13	433.0	6215.1	5747.5
Upper Vent Shaft	Unknown	NA	6701.60	545.5	6156.1	Unknown
Lower Vent Shaft	778	NA	6552.02	395	6157.02	Unknown

The dominant geologic feature in the Velvet-Wood area is the Lisbon Valley Anticline. The Lisbon Valley Anticline is a northwest/southeast feature about 20 miles long that was formed when salt in the Paradox Formation was mobilized. The up-warping and subsequent erosion of the anticline has exposed Pennsylvanian to Cretaceous age rocks along the length of the anticline. Consolidated rocks that crop out in the Lisbon Valley area range in age from Late Pennsylvanian to early Pleistocene. The oldest, the Pennsylvanian Honaker Trail Formation, is exposed in the interior of the anticline with successively younger rocks exposed in the faces of three mesas along the flanks of the anticline. In the Velvet-Wood area the mesa recedes southward stepwise away from the center of the anticline and is known as Three Step Hill. Among the rock units exposed along the Lisbon Valley Anticline are the Permian Cutler Formation, the Triassic Chinle Formation (Moss Back Member) and the Morrison Formation (Salt Wash Member) that contain uranium deposits.

Three Step Hill is composed of three mesas, each progressively higher than the last. The Velvet-Wood Deposit is under the lowest mesa and on the margin of the second. The top of the mesa is a dip slope primarily on the top of the Wingate Sandstone. Low mesas of Kayenta Formation rocks are preserved near the southern base of the dip slope. The dip slope of the middle mesa is composed of resistant sandstone units of the Salt Wash Member of the Morrison Formation. The Brushy Basin Member has been stripped from the plateau but is exposed near the base of the slope of the third mesa. The highest mesa is capped by the Burro Canyon Formation. Some remnants of Dakota Sandstone are exposed on the upper plateau. The dips of the rocks are progressively shallower toward the south. The dips on the lower plateau are about 6-8 degrees and dips on the upper plateau are about 3-5 degrees. Faulting and folding are the major structural features of the Velvet-Wood area. The host rocks of the Velvet-Wood Area are truncated by the faulting on the southwest side of the Lisbon Valley graben. The faults are northeastward dipping normal faults. Displacement on the faults ranges from a few feet to as much as 700 feet. The mineralization of the Velvet-Wood Deposit appears to be fault bounded on the northeast side of the deposit. There are two major faults in the Velvet-Wood area. The rocks between the two faults are folded downward to the northeast (see OP-6 Geology Map). The rocks in the Velvet-Wood area exhibit jointing parallel to the Lisbon Valley anticline and are thought to be tensional joints.



Velvet-Wood Project Stratigraphic Column (Chenowith, 1990)

Uranium mineral resources within and in the vicinity of the Velvet-Wood Project are found in the upper Permian Cutler formation. Many of the other mines in the district were hosted in the basal Moss Back member of the Triassic Age Chinle Formation overlying the Cutler Formation. As shown in the Velvet-Wood Project Stratigraphic Column above there is an erosional unconformity between the Permian and Triassic aged beds where the Triassic Moenkopi formation was eroded away before the placement of the Moss Back Member of the Chinle Formation. Observations from the 2007 and 2008 coring program on the Velvet project has developed the model that mineralization in both formations is related to the unconformity, although the location of mineralization with respect to the contact varies from location to location within the district. Most of the mineral resources in the Cutler occur within six feet of the unconformity. Due to the roughly southward dip of the bedding in the Velvet-Wood project the depth of overburden is greater in the Wood than the Velvet. As such the typical overburden at the Velvet will be approximately 800 to 1,200 ft and the Wood approximately 1,000 to 1,400 ft.

106.9 - Location & Size of Ore, Waste, and Tailings

Waste rock from underground development, when not able to be stowed underground, will be placed in the waste rock stockpile area located immediately southeast of the portal (see Figure OP-5). The waste rock pile will be located on top of the previously reclaimed waste rock area and will encompass approximately 2.5 acres. The waste rock pile will be constructed in lifts, beginning with the maximum overall footprint. Side dumping underground 10-ton mine trucks will exit the portal, and run a right-handed traffic pattern, dumping each lift from the east edge to the west. Following completion of each lift, it will be leveled, and the next lift begun until the pile is completed. The maximum stockpile height will be 40 feet or less. Unclassified waste rock will be placed at slopes of 1.5 H:1V or less for operational conditions. Mineralized waste rock will be placed in the center of the waste rock pile. Whenever possible, once the mine enters the production stage, waste rock will be disposed of in mined-out areas of the underground workings.

The ore stockpile area will be located roughly south of the mine portal as shown on Figure OP-5. This ore stockpile area encompasses approximately 0.5 acres and can accommodate up to 12,000 cubic yards or 15 tons of stockpiled ore assuming an average stockpile height of 15 feet, a stockpile density of 90 lbs/ft^3, and up to seven separate stockpiles.

A water treatment system will be constructed near the mine dewatering vent and settling tanks will be placed within the footprint of the previous evaporation pond, see Figures DET-2 and OP-5. The combined water treatment facilities will encompass less than 3 acres. Steel frac tanks will be placed in all water treatment facilities and will be sized to contain the maximum contents of the water treatment facilities plus ten percent plus one foot of freeboard. Treated water will be used as non-potable water at the surface facilities and no discharge is anticipated at this time.

No on-site processing or tailings areas are proposed.

The underground mine will be accessed through the existing portal; however, the new decline to mineralization will require the removal of interburden waste material. The interburden waste material will be used to increase the size of the work pad and construct the truck loadout area. The six proposed new vent holes will be drilled through the overburden by first drilling a small pilot hole from the surface. A larger diameter head will then be attached at the bottom of the drill string within the mine workings and the vent hole will be reamed from the bottom up with the cuttings falling into the mine. This waste material will be hauled to the waste rock pile or disposed of underground in mined out areas.

There will be no on-site processing (physical or chemical) of ore; accordingly, there will be no tailings or rejected material (e.g., crusher fines). Waste rock will be disposed of in the waste rock pile and in mined-out areas of the underground workings as described above.

Figure DET-1 shows the location and configuration of the proposed waste rock area. The waste rock pile and work pad expansion combined have a maximum projected disturbance area of 2.5 acres and a maximum capacity of 74,000 cubic yards, assuming an in-place waste rock density of about 100 lbs/ft^3. A total volume of 147,000 in-situ cubic yards of waste rock will be generated over the life of the mine. Applying an average swelling factor of 30% to that total means that a total of up to 191,000 cubic yards of unclassified and mineralized waste rock is anticipated based on the detailed mine schedule. As shown on Figure DET-1, the operational design capacity is 74,000 cubic yards of material. The final reclamation capacity of the disturbance footprint can accommodate a total of 75,000-115,000 cubic yards of waste rock. This is due to the ability to adjust the contours of the final design to match the actual production of waste rock from the mine. As such, raising or lowering the final contour designs 5ft or less can adjust up to +/- 40,000 cubic yards while staying within the disturbance footprint and final slope gradients.

The actual amount of waste disposed of in the waste rock pile will depend on the ratio of decline and lateral development to production mining. This ratio could vary considerably on an annual basis depending on market conditions. For example, if production mining is limited during Year 1, most of the waste material mined would have to be hauled to the waste rock pile. Conversely, if production mining is initiated early in Year 2, underground areas will be mined out relatively quickly allowing for their use in waste rock disposal.

There will be no tailings ponds at the Velvet-Wood Mine. There will be no water storage ponds at the Velvet-Wood Mine.

Effluent discharge is planned under the UPDES. All mine water will be treated at the water treatment facilities. Treated mine water will then be used as non-potable water by the surface facilities or discharged down Dry Wash. The storm water catchment ponds are located along the south-western margin of the mine facility’s work pad extension. The stormwater catchment emergency overflow is located in the southeast corner of the lower pond, see DET-5. No discharge from the storm water catchment ponds is anticipated at this time.

106.10 – Amounts of Material Extracted or Moved

A detailed discussion of the expected volumes of ore and waste rock to be mined is given in Section 106.4. A total of 2,190 cubic yards of topsoil will be stripped for the portal area, surface facilities, and water treatment plants. Details concerning topsoil stripping are given in Section 106.6.

IV. Rule R647-4-108 - Hole Plugging Requirements

Vent holes will be plugged in accordance with the requirements of R647-4-108. The concrete collar will be broken and removed, and an area extending a minimum of 4 feet from the edge of the vent in every direction will be excavated three feet below the surface. The casing will be cut off and a polyurethane foam (PUF) plug will be installed 12 feet below the excavated lip. A 16-inch reinforced concrete slab will be laid overtop the plug extending four feet from the vent in every direction. The concrete will be covered with a minimum of 12” cover material with a minimum of 3” topsoil so that revegetation can take place (see AMRP Master Construction Specifications, Drawing 41 in Attachment F).

Exploration drilling will be conducted under separately approved NOI/POOs. Drill hole reclamation will include setting a nonmetallic perma-plug at a minimum of five feet below the surface and filling the hole above with concrete. Holes that encounter non-artesian water will be plugged by placing a 50-foot cement plug immediately above and below the aquifer(s) or filling the hole from the bottom up with a high-grade bentonite/slurry mixture. No artesian water sources have been identified within the project area.

V. Rule R647-4-109 - Impact Assessment

109.1 - Impacts to Surface & Groundwater Systems

Groundwater will be pumped from the underground workings to a water treatment plant located near the vent and the reclaimed evaporation pond area. The groundwater is of marginal quality with elevated concentrations of dissolved solids and sulfate and elevated radionuclide activity levels. Dewatering operations will cause a temporary cone of depression to form in the mine area. The aquifer is not used as a water source; therefore, there will be no impact on water well users. Groundwater levels are expected to return to their pre-mining levels after dewatering operations are discontinued. The Request for Ground Water Discharge Permit by Rule will be provided upon completion. This request also includes groundwater quality data, geotechnical analysis, and a review of the local geology and groundwater.

The storm water catchment ponds have been designed as a zero-discharge facility. The ponds, which will have a clay liner of low hydraulic conductivity, will be situated on top of alternating fill layers of shale/claystone and sandstone. Seepage is expected to be minimal and no impacts to groundwater are projected. The formation being dewatered is approximately 300 feet below the storm water catchment ponds and is the closest aquifer.

Surface water within the project area is limited to ephemeral drainages. These drainages will be protected as described in Section VI and in Attachment G, the Stormwater Pollution Prevention Plan.

109.2 - Impacts to Threatened & Endangered Wildlife/Habitat

There is the potential for four of these species to occur within the project area. Table C2 in Attachment B, Baseline Wildlife, Vegetation, and Soils Survey Report provides more information on the basic habitat requirements and known distributions of these species.

109.3 - Impacts on Existing Soils Resources

Incremental impacts on soil and plant resources will be minimal, as the majority of the areas to be disturbed were disturbed by previous mining activity and have been reclaimed. DOGM still retains a revegetation bond for much of the reclaimed area. No wetlands or threatened, endangered, and sensitive plant species were identified as being within or adjacent to the project. Although the national wetland inventory shows wetlands in the area of the dewatering ponds, they do not exist as discussed in Section 106.7. Other mapped wetlands are outside the proposed disturbance areas. Impacts to ephemeral drainages and associated riparian areas will be limited to maintaining the existing road culverts that are installed within drainages.

Soil and plant mitigation measures will include salvaging the available topsoil and any suitable subsoil material prior to re-disturbing an area. Erosion and sediment control measures will be implemented, as described in Attachment G, to minimize loss of soil resources. Vegetation resources will be mitigated by seeding topsoil stockpiles and any reclaimed areas during the fall planting season. Upon mine closure, the disturbed areas will be revegetated as described in Section VII below.

109.4 - Slope Stability, Erosion Control, Air Quality, & Safety

Slope Stability: Surface excavations with attendant highwalls are not proposed, as all mining will be done using underground methods. Natural highwalls exist in the project area. Constructed slopes include the waste rock pile and work pad expansion. The waste rock pile will have one bench and a maximum bench height of 40 feet, which is about the same height as the previous waste rock pile that was constructed and reclaimed in the same location. Given the relatively small vertical height of the proposed benches and the apparent stability of the previous waste rock pile, the storage area is expected to be stable during mine operations. The waste rock pile and work pad expansion will be regraded to achieve final slopes of 3H:1V or less steep.

Erosion: Areas of potential erosion include the waterline corridor, topsoil stockpiles, waste rock pile slope, work pad expansion slope, vents, and the ore stockpiles. The remaining areas are relatively flat with low potential for erosion. The downslope portions of the waterline corridor will be stabilized by broadcast seeding the disturbed areas after construction is complete. Topsoil stockpiles will be seeded during the first fall planting season after the soil is stockpiled. Some erosion will occur on the waste rock slopes and the sides of the ore stockpiles as they will be in a state of continual change and disturbance during operations.

The impact from erosion will be minimized by installing sediment control measures. Erosion from the waste rock pile, work pad expansion, ore stockpile area, and topsoil stockpiles will be captured by drainage ditches located along the access roads. This ditch will discharge into stormwater catchment ponds, which have been designed to not overflow under the 10-year 24-hour storm event. Stormwater catchment ponds will be mucked out prior to capacity being reduced to a point where the 10-year 24-hour event could not be retained. Undisturbed buffer zones, earthen berms, or concrete barriers will be installed between the remaining areas of proposed disturbance (i.e., mine buildings, storage yards, and parking areas). Earthen berms and/or straw-bale barriers may also be installed in areas prone to erosion.

Air Quality: The Air Authorization Approval Order is located in Attachment E. The principal source of project emissions is from mining equipment. These vehicles will be equipped with engines and air filters that meet state emissions standards. Fugitive dust on mine roads will be controlled through enforcement of speed limits and treatment of the roads with magnesium chloride or a similar compound. A water truck will also be used to spray the mine roads, waste rock pile, and ore stockpiles within the permit area, as needed.

Public Health and Safety: The mine, which is located in a remote area, experiences low levels of vehicle traffic from ranchers and all-terrain vehicles (ATVs). Warning and speed limit signs will be posted along the county road to control speeds and warn drivers of the proximity of mine equipment. When not in active use, portals, adits, buildings, and gates will be locked to preclude unauthorized access.

109.5 – Actions to Mitigate any Impacts

The storm water catchment ponds have been designed as a zero-discharge facility with a clay liner of low hydraulic conductivity. Seepage from the ponds is expected to be minimal and no impacts to groundwater are projected. Further discussion of the ponds can be found in Section 109.1.

Surface water within the project area is limited to ephemeral drainages. These drainages will be protected as described in Section VI and in Attachment G, the Stormwater Pollution Prevention Plan. Erosion on the site will be controlled through broadcast seeding the downslope portions of the waterline corridor and topsoil piles, and with the use of sediment controls. Further details on mitigation related to surface hydrology are given in Section 109.4.

Groundwater is anticipated to be impacted during mine dewatering as a cone of depression develops around the mine workings. These levels will return to their original static level following the cessation of mine dewatering activities as they have in the previous mining operations.

In the Base case scenario, the majority of waste rock will be back-stowed underground in mined out areas to minimize the footprint of the waste rock pile on the surface. The reclamation plan described herein is a geomorphically stable surface that approximates native ground and runoff patterns. Alternative disposal of up to an additional 40,000 cubic yards of material in the reclaimed waste rock pile is possible while keeping the reclamation contours within 5ft of the original design.

VI. Rule R647-4-110 - Reclamation Plan

110.1 - Current & Post Mining Land Use

Pre-mining and current land use include livestock grazing, wildlife habitat, and recreation.

The proposed post-mine land use is livestock grazing, wildlife habitat, and recreation.

110.2 - Roads, Highwalls, Slopes, Drainages, Pits, etc., Reclaimed

Immediately following cessation of mining and dewatering activities it is anticipated that the ground water level will begin to recover towards its original level. Ground water monitoring will be ongoing during reclamation as during mining and will continue after reclamation until sufficient equilibrium is maintained and the monitoring wells removed.

Reclamation treatments are shown on Figures RP-1 and RP-2 and described in more detail below.

Reclamation design contours are shown on Figure RP-1. The reclamation plan is subsequently described in detail. Revegetation will adhere to the specifications provided in Attachment F, Reclamation, and mine closure details are shown on Figure RP-2.

Roads to be reclaimed are identified on Figure RP-1. These roads are pre-existing and incorporated either within the existing permit or recent exploration notices. The main access road from the country road to the portal will be surveyed for any deleterious material. If deleterious material is found, it will be excavated and placed in the central portion of the waste rock pile and isolated. For roads which are located on bedrock where natural vegetation did not exist, closures will be created utilizing on site boulders to prevent future access. For roads which occur in areas of alluvium and/or native topsoil materials with attendant natural vegetation, the roads will be reclaimed by:

1. Regrading any cuts and fills to reestablish the original ground contours and drainages.
2. Ripping the roads to a depth of 18 to 24 inches.
3. Placing a minimum 3-inches of loose topsoil in locations where topsoil was removed.
4. Revegetation will adhere to the specifications as provided in Attachment F.

No highwalls exist or will be created through the planned operations.

Slopes will generally be regraded to approximately original contours. Where this is not possible, such as the waste rock pile, the maximum reclamation slope shall be 3:1 (horizontal to vertical) with most slopes at 4:1 or less. Slopes will be variable, to promote vegetative diversity, and to promote a more natural appearance. Revegetation will adhere to the specifications as provided in Attachment F.

Liners will be present underneath water treatment tanks and fuel storage tanks. After removal of the tanks, the liners and any sediment that has accumulated on them over time will be folded up and taken to the City of Monticello Landfill or Lisbon Valley Mining Solid Waste for disposal. The berms will be knocked down and the area regraded to match the surrounding topography.

Existing and planned disturbances generally do not impact drainages. As shown on Figure RP-1, the proposed reclamation surface exists on a ridge between natural drainages, and the earthworks design for the reclamation of the waste rock pile includes drainages which will divert runoff from the native ground away from the reclamation surface. In areas where drainage reclamation is necessary, such as along the access road, the areas would be returned to approximate original contours and revegetated in accordance with the specifications provided in Attachment F.

Although existing and planned disturbances generally do not impact existing drainages, second and third order drainages will be constructed in the re-graded production area. These constructed drainages are designed to be geomorphically stable and mimic the function of natural ground. Figure RP-2 provides typical profile and cross-sectional views of these channels.

Reclamation design contours are shown on Figure RP-1. The final regraded surface will be designed to be geomorphically stable utilizing a Natural Regrade™ design. The final reclamation surface as shown is based upon the estimated maximum volume of waste brought to the surface without back-stowing as described in the discussion of ore and waste stockpiling in the Operation Plan. The reclamation design presented herein is of the maximum height and steepest likely slopes on site yet is geomorphically stable and based upon conservative hydrologic parameters. As it is anticipated that a certain amount of the waste materials can be safely stowed underground, the actual final reclamation surface is anticipated to be lower and flatter than the current design, thus inherently more stable. The hydrologic input parameters, design criteria, and reclamation design results are provided in, Attachment F.

Prior to final reclamation, all ore stockpiled on site will be hauled to the mill. The superblocks, liner, and concrete footer will be cleaned and removed from the site to be disposed of at a licensed facility. The eastern edge of the waste stockpile will be reduced and placed along the southern toe of the waste stockpile. The waste stockpile will be graded to elevations approximately 8 feet below the anticipated final reclamation surface. The unclassified materials from the initial decline development, previously stockpiled and utilized to expand the work area pad, will then be placed to the lines and grades shown in Figure RP-1. Rock materials exceeding a D50 of 6 inches will be placed in the drainage channels on the reclamation surface to ensure that the surface will remain non-erosive, exceeding the design parameters. This will prevent exposure and potential off-site transportation of the mine waste and associated radiometrically elevated materials encapsulated below the final reclamation surface.

Topsoil material will be placed on the reclaimed surface at a minimum depth of three inches. If sufficient topsoil is not located within the Project Area for the three-inch minimum coverage depth, it will be imported. The source is not known at this time, however, should the need for imported topsoil arise a source will be identified and approved by the Division prior to importing it to the site. Revegetation of the site will be completed utilizing an approved seed mixture containing drought resistant native plant species as described in Attachment F.

Mine portal closure details are shown on Figure RP-2. Permanent mine closure will employ a grouted rock bulkhead to be constructed in the decline at a location where a sufficient thickness of competent roof rock exists to prevent future subsidence of the mine void which may report to the surface. The bulkhead shall extend a minimum of 2 mine heights length down the decline (approximately 24 ft) and consist of waste concrete from building, ore stockpile, and unclassified materials. This bulkhead material will be grouted in following placement using cementitious grout using tremmie or other piping from the portal to the face of the bulkhead and pumped until refusal. The remaining decline upslope of the bulkhead will be shot down and the surface regraded for positive drainage away from the reclaimed portal.

Permanent closure of mine vents will be done in accordance with DOGM preapproved specifications for a concrete slab closure with PUF (polyurethane foam) shoring (Drawing 41, AMRP Master Construction Specifications in Attachment F). After surface structures have been uninstalled and appropriately disposed of, a 12-foot PUF plug shall be installed according to manufacturer specifications with a 2” diameter steel drainage pipe down the center. The PUF plug will be allowed to cure for at least one hour before being overlaid with a reinforced concrete slab of minimum 16” thickness in accordance with DOGM preapproved specifications for a reinforced structural slab with a drain (Drawing 46, AMRP Master Construction Specifications in Attachment F). This slab will extend a minimum of four feet from the edge in every direction and will slope inward towards the drainage pipe. An impermeable membrane shall be utilized overtop the concrete slab in order to facilitate groundwater movement to the drain. A minimum of 12” fill will overlay the concrete slab, sloped to direct surface water away from the closure.

Exploration and geotechnical drill holes are not included in the NOI/PO, but rather are addressed in separate, stand-alone exploration notices. Unless approved otherwise, drill holes will be abandoned in accordance with Utah Administrative Code (UAC) Rule R647-4-108 (See Section V). Drill pad areas will be reclaimed by replacing salvaged topsoil, regrading, and ripping the disturbed area, and broadcast seeding with the approved seed mix.

The project does not include a tailings facility.

The project does not include leach pads.

All available stockpiled topsoil will be utilized for site reclamation. Any remaining ore stockpiles and/or low-grade ore stockpiles will be shipped to the mill for processing if market conditions are favorable. If the ore stockpiles cannot be shipped to the mill due to economic or other conditions, they will be treated as marginal material and disposed of with other such material within the waste rock pile or hauled and backstowed underground as described above. After regrading and redistribution of salvaged topsoil, revegetation will adhere to the specifications as provided in Attachment F.

110.3 – Facilities Left for Post Mining Land Use

No surface facilities will remain on site after demolition and reclamation. No power poles exist onsite at the time of this Plan of Operations. Any power utilities such as buried lines or poles owned by the operator within the permit boundary will be removed. Power poles or lines that lay outside the permit boundary will be owned by the power company and may remain.

110.4 – Treatment & Disposition of Deleterious and/or Acid Forming Material

Waste rock materials remaining at the surface upon completion of mining will be sampled and tested for acid base potential as previously described. At the time of mine closure, the remaining petroleum products on site will be used for their intended purpose, transported to another facility, or returned to the vendor. The used oil will be picked up by a certified hydrocarbon recycler, such as Rock Canyon Oil. After removal of their contents, the tanks will be shipped to another facility, sold, or properly decommissioned and recycled at the Canyonlands Transfer Station. The liner underneath the fuel station will be exposed, cut into sections, and hauled to the City of Monticello Landfill for disposal. Any soil found to have petroleum/oil contamination would be characterized, removed from the site, and taken to the City of Monticello Landfill. The solvent station and any remaining solvent will be returned to the vendor. The road stabilizing products will be used to control dust during reclamation and the tanks will be removed and shipped off site.

Trailers will be hauled to another facility, sold, or hauled to the City of Monticello Landfill for disposal. Prefabricated buildings will be disassembled and reassembled at another facility, sold, or disposed of at the City of Monticello Landfill. Solid waste meeting the definition of “inert waste” under UAC Rule R315-301-2 (e.g., concrete, blocks, brick, incidental rebar, and glass) will be removed from public lands and disposed of at the City of Monticello Landfill. All concrete foundations and pads will be broken, using a hydraulic excavator with a concrete breaker (or equivalent) to dimensions of five feet or less. The broken concrete will be removed from public lands and disposed of at the City of Monticello Landfill.

The mine site will be provided with storm water drainage control structures, however, it is anticipated that these facilities will not be receiving appreciable sediment from either the waste rock or the ore stockpile due to physical conditions and controls at those locations. Accordingly, it is most likely that cleanup will not be necessary at these locations. However, any sediment contained within the stormwater catchment ponds will be identified by gamma-survey following mining activities. If the sediments are found to be contaminated, they will be removed and placed within the mine workings. In addition, during mine operations the stormwater catchment ponds will be inspected periodically for sediment buildup and, as necessary, sediment removal and in-mine disposal would be completed to maintain the integrity and size of the ponds.

110.5 - Revegetation Planting Program

All available topsoil will be utilized for revegetation of disturbed areas following treatment of the subgrade for acid forming materials. After regrading is complete and topsoil is placed, agricultural ripping will be done on any compacted topsoil areas to a minimum of 3” depth at a 12” spacing. Soil amendments will then be spread on the surface as needed. The type and application rate of amendments will be determined by the results of soil sampling. Agricultural discing of the amended surface will be completed to a depth of 8”. Pitting and seeding will then be done with the following approved seed mix:

Recommended Revegetation Species List		
Common Name	Species Name	*Rate lbs/ac (PLS)
Grasses (Choose 4)		
*Indian ricegrass	Achnatherum hymenoides	2.5
*Galleta grass	Pleuraphis jamesii	2.0
Blue grama	Bouteloua gracilis	0.2
Purple three-awn	Aristida purpurea	2.0
Sand dropseed	Sporobolus cryptandrus	0.10
Saline wildrye	Leymus salinus	3.0
Forbs (Choose 2)		
Annual sunflower	Helianthus annus	1.0
*Scarlet globemallow	Sphaeralcea coccinea	1.0
Pacific aster	Aster chilensis	0.10
Shrubs (Choose 3)		
Utah serviceberry	Amelanchier utahensis	2.0
Fourwing saltbush	Atriplex canescens	2.5
*Black sagebrush	Artemisia nova	0.25

*Mormon tea	Ephedra viridis	2.0
Yellow rabbitbrush	Chrysothamnus viscidiflorus	0.20

*Division preferred

Successful revegetation will consist of 70% of pre-mining vegetation coverage across the revegetated area.

Prior to topsoil placement the unclassified final graded surface will be sampled for acid/base potential and other factors that may affect topsoil contamination and plant growth. Areas that are determined to be unsuitable for topsoil placement will be sub excavated and then backfilled with clean interburden waste material or treated with lime or other amendments prior to topsoil placement.

I.Rule R647-4-112 - Variance

Anfield is not requesting any variances at this time.

XI. **SIGNATURE REQUIREMENT**

I hereby certify that the foregoing is true and correct. **(Note: This form must be signed by the owner or officer of the company/corporation who is authorized to bind the company/corporation).**

Signature of Permittee / Operator/Applicant: ______________________________
Name (typed or print): Joshua Bleak
Title/Position (if applicable): President
Date: March 27, 2025

PLEASE NOTE:
Section 40-8-13(2) of the Mined Land Reclamation Act provides for maintenance of confidentiality concerning certain portions of this report. Please check to see that any information desired to be held confidential is so labeled and included on separate sheets or maps. Only information relating to the location, size or nature of the deposit may be protected as confidential.

Confidential Information Enclosed: (X) Yes ( ) No

Exhibit 20

TSX. V: **AEC** OTCQB: **ANLDF** FRANKFURT: **0AD**

Anfield’s Most Advanced Uranium/Vanadium Asset

Acquired alongside the Shootaring Canyon Mill in 2015, this project holds significanthistorical mineral resources. With measured and indicated categories containing 4.6 million pounds ofeU3O8 (0.285% grade) and inferred categories holding 552,000 pounds of eU3O8 (0.320% grade) and7.3Mlbs of V2O5 (0.404% grade), Velvet-Wood demonstrates its potential.

From 1979 to 1984, the project yielded significant results, recovering around 4 million pounds of U3O8and 5 million pounds of V2O5 from mining approximately 400,000 tons of ore with grades of 0.46%U3O8 and 0.64% V2O5. The Velvet mine retains underground infrastructure, including a 3,500 ft long,12' x 9' decline to the ore body. As Anfield Energy’s most advanced uranium asset, Velvet-Woodsignifies a potential near-term path to uranium and vanadium production. Join us as we unlock theproject’s full potential.

Preliminary Economic Assessment:

Download Full Report

Velvet-Wood Project

Highlights

1. The most advanced asset in Anfield's uranium portfolio.
2. Between 1979 and 1984 approximately 400,000 tons of ore were mined from the Velvet deposit at average grades of 0.46% U3O8 and 0.64% V2O5 (recovering approximately 4 million pounds of U3O8. and 5 million pounds of V2O5).*
3. Some underground infrastructure is already in place at the Velvet mine, including a 3,500 ft long, 12' x 9' decline to the ore body.
4. The historical mineral resources of the combined Velvet and Wood mines have been estimated to comprise 4.6 million pounds of U3O8 at an average grade of 0.285% U3O8 (measured and indicated resource), along with 638,500 pounds of U3O8 at an average grade of 0.173% U3O8 and 4.7 million pounds of V2O5 at an average grade of 0.404% V2O5 (inferred resource).**

* Source: Lisbon Valley, Utah's Premier Uranium Area, A Summary of Exploration and Ore Production, William L. Chenoweth, Utah Geological and Mineral Survey Open-File Report 188, July 1990.

**Source: 2023 PEA, The PEA completed for the combined Velvet-Wood and Slci Rock projects has been authored by Douglas L. Beahm, P.E., P.G. Principal Engineer, of BRS Inc., Terence P. (Terry) McNulty, P.E., D. Sc., of T.P. McNulty and Associates Inc.

See "Summary of Uranium One Conventional Uranium Asset Transaction" for more information regarding the status of the properties described in this section.

Table 1: Velvet-Wood Project Historic Resource

Area/Classification	Pounds eU3O8	Tons	Average Grade %eU3O8
Velvet Measured Mineral Resource	1,966,000	362,600	0.27
Velvet Indicated Mineral Rsource	548,000	71,200	0.38
Wood Indicated Mineral Resource	2,113,000	377,000	0.28
TOTAL MEASURED AND INDICATED MINERAL RESOURCE	4,627,000	810,800	0.29
TOTAL INFERRED MINERAL RESOURCE	552,000	87,000	0.32

*numbers rounded

Source: Velvet-Wood Mine Uranium Project, San Juan County, Utah USA 43-101 Mineral Reserve and Resource Report, Author: BRS Inc.; Date: 11/14/2014

Location

The Velvet area is located in San Juan County, Utah, approximately 31 miles from Monticello, Utah, in Township 31 South, Range 25 East, Sections 2, 3, 4 and 10, at Latitude 38° 07' 00" North and Longitude 109° 09' 00" West. The Wood area is located in Township 31 South, Range 26 East, Sections 6 and 7 and Township 31 South, Range 25 East, Sections 1, 11, and 12 at Latitude 38° 08' 00" North and Longitude 109° 06' 00" West. Project ownership includes unpatented mining claims and a State of Utah mineral lease as shown on Figure 4.1, totaling approximately 2,166 acres related to the Velvet and Wood mine areas as shown on Figure 4.1.

History

The ownership history of the Velvet-Wood mineral holdings has undergone changes over time. Anfield Energy acquired the Velvet-Wood mine and other conventional uranium assets from Uranium One in August 2015.

The Velvet-Wood Uranium and Vanadium Project is comprised of two separate areas that were historically owned by different companies. The Velvet area was previously held by Atlas Minerals, who conducted mining operations on parts of the mineralization. Simultaneously, the Wood area was owned by Uranerz during a similar time period. Uranerz conducted drilling activities from 1985 to 1991, with 120 rotary holes drilled, and outlined the current Wood mineral resource area (Chenoweth, 1990). However, it is important to note that the Wood area described in this report was drilled but not mined.

Geology

The Velvet-Wood project is situated within the Lisbon Valley uranium district, which holds the distinction of being the largest uranium-producing district in Utah. From 1948 to 1988, the Lisbon Valley, also known as the Big Indian Wash District, produced five times more uranium than any other district in Utah. The total production during this period amounted to an impressive 77,913,378 pounds of U308 (uranium concentrate) at an average grade of 0.30% U308 (Chenoweth, 1990).

In the Velvet and Wood areas of the project, uranium mineralization is found within sandstone units of the Cutler Formation. These sandstones are fluvial arkose that have undergone a process called bleaching. The mineral deposits within the project are irregular and take the form of tabular bodies (Denis, 1982). They are located at the base, top, or in close proximity to pinch-outs (narrowing) of the sandstone bodies (Campbell and Mallory, 1979). The primary productive zone within the Cutler Formation occurs near the unconformity, which is the boundary, between the Cutler Formation and the overlying Chinle Formation.

Permitting

Permitting for Velvet-Wood mining operations requires various approvals from the state of Utah Division of Oil, Gas and Mining (DOGM) and the US Bureau of Land Management (BLM). There is an existing Large Mine permit for the Velvet Mine which will need to be updated and revised.

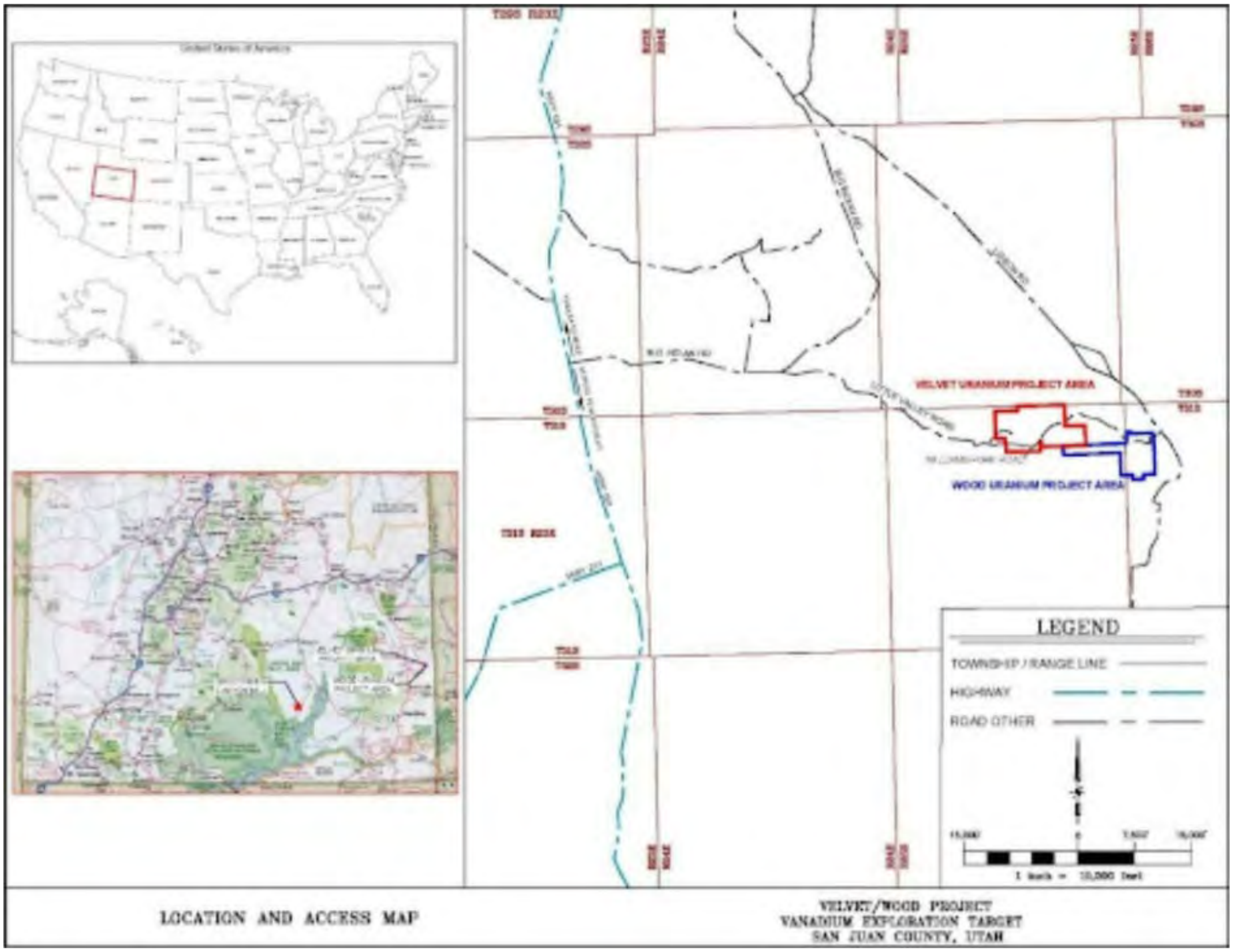
Access

Portions of the Velvet deposit have undergone previous mining activities, which involved accessing the mineralization through a portal and decline. The mine entrance has since been closed off with backfill, but has the potential to be reopened for future operations. The Velvet portal can be reached via well-maintained roads, starting with the Big Indian Road. This road is a paved surface road that branches off from U.S. Highway 191, approximately 19 miles north of Monticello, Utah, or 34 miles south of Moab, Utah.

The Big Indian Road extends eastward and forms a loop with the Lisbon Road, serving properties in the Lisbon Valley area. Another road, San Juan County Road 112 (Williams Fork), branches off from the Big Indian Road about 5.5 miles east of its intersection with Highway 191. There is a private access road that connects with County Road 112 around 6 miles southeast of its intersection with the Big Indian Road. Travelling along these roads for about one mile northeast will lead to the Velvet Mine portal. The described route can be navigated using a 2-wheel drive vehicle on existing county and/or two-track roads. The project is located approximately 10 miles south of La Sal, Utah. Most transportation for the project will be facilitated by commercial trucks. Access to exploratory drill sites and vent locations is provided through existing roads connected to the main access point at the

Velvet portal and the Lisbon Road.

The Wood mine area is situated approximately 3 miles east of Velvet and can be accessed via County Road 112. It is also accessible from the east using the Lisbon Valley Road and County Road 112.



The PEA for Velvet-Wood/Slick Rock was authored by Douglas L. Beahm, P.E., P.G. Principal Engineer, Harold H. Hutson, P.E., P.G. and Carl D. Warren, P.E., P.G., of BRS Inc., Terence P. (Terry) McNulty, P.E., D. Sc., of T.P. McNulty and Associates Inc. (May 6, 2023). Mineral resources are not mineral reserves and do not have demonstrated economic viability in accordance with CIM standards. GT cut-off varies by locality from 0.25%-0.50%.

Exhibit 21

ANFIELD Energy

PURSUIT OF HUB-AND-SPOKE URANIUM & VANADIUM PRODUCTION STRATEGY IN THE UNITED STATES

SEPTEMBER 2023

SAFE HARBOUR

All statements, other than statements of historical fact, contained in this presentation constitute “forward-looking statements” within the meaning of the United States Private Securities Litigation Reform Act of 1995, and “forward-looking information” under similar Canadian legislation and are based on the reasonable expectations, estimates and projections of the Company as of the date of this presentation. Forward-looking statements and forward-looking information include, without limitation, possible events, trends and opportunities and statements with respect to possible events, trends and opportunities, including with respect to, among other things, the growth of the phosphate market, global market trends, expected industry demands, the Company’s business strategy and investment criteria, the nature of potential business acquisitions, costs and timing of business acquisitions, capital expenditures, successful development of potential acquisitions, currency fluctuations, government regulation and environmental regulation. Generally, forward-looking statements and forward-looking information can be identified by the use of forward-looking terminology such as “plans”, “expects” or “does not expect”, “is expected”, “budget”, “scheduled”, “estimates”, “forecasts”, “intends”, “anticipates” or “does not anticipate”, or “believes”, or variations of such words and phrases or state that certain actions, events or results “may”, “could”, “would”, “might” or “will be taken”, “occur” or “be achieved”. Forward-looking statements and forward-looking information are necessarily based upon a number of estimates and assumptions that, while considered reasonable by the company as of the date of such statements, are inherently subject to significant business, economic and competitive uncertainties and contingencies. The estimates and assumptions contained in this presentation, which may prove to be incorrect, include, but are not limited to, the various assumptions of the company set forth herein. Known and unknown factors could cause actual results to differ materially from those projected in the forward-looking statements and forward-looking information. Such factors include, but are not limited to fluctuations in the supply and demand for uranium, changes in competitive pressures, including pricing pressures, timing and amount of capital expenditures, changes in capital markets and corresponding effects on the company’s investments, changes in currency and exchange rates, unexpected geological or environmental conditions, changes in and the effects of, government legislation, taxation, controls and regulations and political or economic developments in jurisdictions in which the Company carries on its business or expects to do business, success in retaining or recruiting officers and directors for the future success of the Company’s business, officers and directors allocating their time to other ventures; success in obtaining any required additional financing to make target acquisition or develop an acquired business; employee relations, and risks associated with obtaining any necessary licenses or permits. Many of these uncertainties and contingencies can affect the company’s actual results and could cause actual results to differ materially from those expressed or implied in any forward-looking statements and forward-looking information made by, or on behalf of, the Company. There can be no assurance that forward-looking statements and forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such statements. All of the forward-looking statements and forward-looking information made in this presentation are qualified by these cautionary statements. Although management of the Company has attempted to identify important factors that could cause actual results to differ materially from those contained in forward-looking statements or forward-looking information, there may be other factors that cause results not to be as anticipated, estimated or intended. There can be no assurance that such statements will prove to be accurate, as actual results and future events could differ materially from those anticipated in such statements. Accordingly, readers should not place undue reliance on forward-looking statements and forward-looking information. The Company does not undertake to update any forward-looking statements or forward-looking information that are incorporated by reference herein, except in accordance with applicable securities laws. Timelines used in this presentation are for the purpose of aiding management in the planning and implementation of the project and are not based on a detailed assessment of project requirements. Consequently the timelines are subject to material revision based on when technical reports and/or feasibility studies, if any, are completed. Future phases of the project are contingent upon completion of preceding phases. Nothing in this presentation should be construed as either an offer to sell or a solicitation of an offer to buy or sell shares in any jurisdiction. TECHNICAL DISCLAIMER: This presentation contains references to historical resources. Anfield is not treating the historical estimates as current mineral resources or mineral reserves. A qualified person has not done sufficient work to classify the historical estimates as current mineral resources or mineral reserves. All historical resources referenced in this report, unless otherwise noted, are from technical reports prepared by well-known mineral exploration and mining consulting firms using current CIM standards and terminology. The Company intends to work with the same groups to complete the reports such that they comply with all requirements of NI 43-101. Doug Beahm, P. Eng., is the Qualified Person who has reviewed and approved the technical content of this presentation.

CAPITAL MARKETS PROFILE

EXCHANGE/SYMBOL	
TSX Venture	AEC
OTCQB	ANLDF
CAPITAL STRUCTURE	
Recent share price	C$0.09/sh
52-week range	C$0.04 - C$0.10
Basic shares outstanding	$945.7M
Warrants outstanding	$323.5M
Options outstanding	$62.4M
Market capitalization (basic)	$85.1M
Market capitalization (fully-diluted)	$119.8M
MAJOR SHAREHOLDERS (% OF BASIC S/O)	
enCore Energy Corp.	~20%
Uranium Energy Corp.	~10%
Management and Insiders	~4%
ANALYST COVERAGE	
RED CLOUD SECURITIES INC.	C$0.20/sh target

REASONS TO INVEST

- Robust asset base including consolidated assets in the prolific Uravan Mineral Belt of Colorado and Utah
- Growing uranium resource base with large strategic vanadium endowment
- Shootaring Canyon Mill is one of only three licensed, permitted and constructed uranium mills in the US
- Strong fundamentals for uranium and vanadium, particularly with respect to domestic US developers and producers
- Debt free post-financing, with both UEC and enCore as strategic shareholders
- Compelling valuation relative to peers

MACRO OVERVIEW: URANIUM

GEOPOLITICAL RISK INHERENT IN THE SECTOR

- Russia: conversion and enrichment dependence in the West
- China: Kazakhstan declared further energy cooperation; trading hub proposed
- USA: world's largest installed reactor base, but domestic production essentially zero in Q4/22

BUT OPPORTUNITIES TAKE SHAPE

- China, UAE, India, Eastern Europe: reactors approved
- Japan: restart of some reactors and cap lifted for life extension of others
- USA: Uranium Reserve Program acquired 1Mlbs at an average U price of $60/lb

SUPPLY REMAINS AN ISSUE

- Cameco supplying China Nuclear and Ukraine Energoatom, removing material from the North American market
- Spain denied Berkeley Energia a license for its Salamanca processing plant
- SPUT, Yellowcake purchasing pounds from the spot uranium market
- Kazatomprom forecast reduction for 2023 and 2024, but has signed significant long-term contracts with China

DEMAND INCREASING, SUPPLYING TIGHTENING: URANIUM PRICE HAS TO INCREASE TO BRING MORE PRODUCTION ONLINE

HUB-AND-SPOKE OPPORTUNITY IN THE URAVAN MINERAL BELT

- 750 tpd permitted Shootaring Canyon Mill in Utah which underpins Anfield's hub-and-spoke strategy
- 5 properties containing uranium resources which will serve as feedstock to the Mill
- Three of the aforementioned projects either contain both uranium and vanadium resource or produced both in the past
- Long-term conventional uranium and vanadium mine and mill complex further establishes strategic objective of production control
- Potential for vanadium offtake opportunities

PROJECT	LOCATION	CLASSIFICATION	TONS (KT)	URANIUM GRADE (% U_3O_8)	CONTAINED URANIUM (MLBS U_3O_8)	VANADIUM GRADE (% V_2O_5)	CONTAINED VANADIUM (MLBS V_2O_5)
VELVET-WOOD	Utah	M & I	811	0.29%	4.6	-	-
		Inferred	87	0.32%	0.6	0.404%	7.3
SLICK ROCK	Colorado	Inferred	1,760	0.224%	7.9	1.35%	47.1
WEST SLOPE	Colorado	Indicated	1,367	0.197%	5.4	-	-
		Inferred	1,367	-	-	0.984%	26.9
		Historic*	630	0.31%	3.9	1.59%	20.0
FRANK M	Utah	Historic*	1,137	0.101%	2.3	-	-
FINDLAY TANK	Arizona	Historic*	211	0.226%	1.0	-	-

* Denotes resources that the Company does not consider to be current
Technical report disclosure (including cut-offs) for each project can be found on each project's respective slides herein

CORE ASSETS IN HUB-AND-SPOKE PRODUCTION STRATEGY

SHOOTARING CANYON MILL (100% INTEREST)

- One of only three licensed, permitted and constructed uranium mills in existence in the U.S. (acquired from Uranium One in 2015)
- Conventional acid leach facility licensed to process up to 750 tons of ore per day

VELVET-WOOD PROJECT (100% INTEREST)

- Historic production of 4 Mlbs U_3O_8 and 5 Mlbs V_2O_5
- M&I mineral resource of 4.6 Mlbs U_3O_8 grading 0.29% plus additional inferred resources of 0.55 Mlbs U_3O_8 grading 0.32%
- PEA completed in 2023 showing positive economics

WEST SLOPE PROJECT (100% INTEREST)

- Property hosts nine historic uranium and vanadium mines
- Updated resource estimate containing 5.4 Mlbs U_3O_8 Indicated + 26.9 Mlbs V_2O_5 Inferred, plus historic resources containing an additional 3.9 Mlbs U_3O_8 and 20.0 Mlbs V_2O_5

SLICK ROCK PROJECT (100% INTEREST)

- Inferred inferred mineral resources of 7.9 Mlbs eU_3O_8 grading 0.224% and 47.1 Mlbs V_2O_5 grading 1.35%
- PEA completed in 2023 showing positive economics
- Project area is at the apparent intersection of two major mineral trends in the Uravan Mineral Belt
- Future target exploration focus on the down-dip extensions of the Burro and Sunday-Carnation mineral trends

ENVISIONING A CENTRALIZED PROCESSING OPERATION:
SHOOTARING CANYON MILL IS NEAR SEVERAL MULTI-MILLION POUND URANIUM DEPOSITS IN UTAH

Technical report disclosure (including cut-offs) for each project can be found on each project's respective slides herein

SECONDARY PIPELINE ACQUISITION
MARQUEZ-JUAN TAFOYA PROJECT

MARQUEZ-JUAN TAFOYA PROJECT
- Acquired from enCore Energy in 2023
- Historical Indicated uranium resource of 18.1Mlbs at an average grade of 0.127%
- Historical PEA returned NPV of $20.6M at a 7% discount rate and a $60/lb uranium price*

VALUE PROPOSITION
- Largest single uranium resource within Anfield's portfolio
- Advanced asset with historical resource – in line with Anfield's acquisition strategy
- Entry point into another historically-prolific uranium state – New Mexico
- Could serve as an anchor asset for Anfield's secondary production pipeline and longer-term production feed for Shootaring

INDICATED MINERAL RESOURCE

MINIMUM 0.60. GT	TONS	$\%EU_3O_8$	POUNDS
ROUNDED TOTAL (x 1,000)	7,100	0.127	18,100

*Marquez-Juan Tafoya Uranium Project, 43-101 Technical report, Preliminary Economic Assessment, BRS, Inc., June 9, 2021, prepared for enCore Energy Corp..

ANFIELD'S STEPS TO PRODUCTION

NEAR-TERM PRODUCTION PLAN:
SHOOTARING, VELVET-WOOD AND SLICK ROCK

- Currently engaged with both PSE to outline the mill reactivation plan and Utah DEQ to facilitate the advancement of Anfield's 750tpd Shootaring Canyon mill from its current Standby position to Operational
- Velvet-Wood and Slick Rock Preliminary Economic Assessment (PEA) results are robust: NPV of US$238M using an 8% discount rate, U price of US$70 and V price of US$12
- Addition of vanadium circuit to plant provides alternate valuable commodity

MID-TERM PRODUCTION PLAN:
WEST SLOPE

- Advance its current West Slope uranium/vanadium resource to a PEA in order to increase its production pipeline
- Commission a resource report with regard to some, or all, of the 5 remaining West Slope properties not captured in the initial resource of PEA*

LONGER-TERM PRODUCTION PLAN:
ACQUIRE ADDITIONAL ASSETS AND ASSESS SECONDARY ASSETS WITHIN THE PORTFOLIO

- Seek out other assets to increase production pipeline or create an additional hub
- Assess projects within the portfolio and determine timelines for potential production: Marquez-Juan Tafoya, Frank M, Findlay Tank, Artillery Peak, Marysvale, Calf Mesa

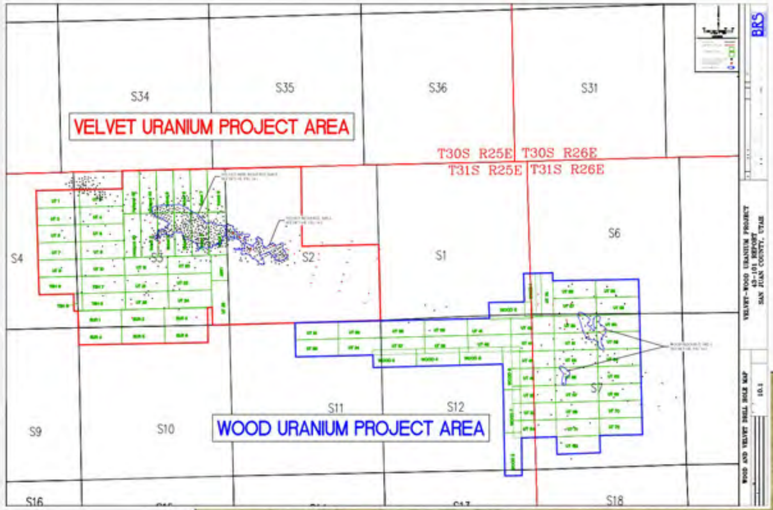
*This economic assessment is preliminary in nature and it includes inferred mineral resources that are considered too speculative, geologically, to have the economic considerations applies to them that would enable them to be categorized as mineral reserves. There is no certainty that the preliminary economic assessment will be realized. Mineral resources are not mineral reserves as they do not have demonstrated economic viability.

VELVET-WOOD PROJECT

UTAH

VELVET-WOOD PROJECT

OWNERSHIP	• 100% owned by Anfield • Purchased from Uranium One in August 2015
LOCATION	• 2,425-acre property located in the Lisbon Valley Uranium District in San Juan County, Utah
HISTORY	• Historic production of 4 Mlbs U_3O_8 and 5 Mlbs V_2O_5 (1979-1984), mined at an avg. grade of 0.46% U_3O_8 and 0.64% V_2O_5
INFRASTRUCTURE	• Access to paved roads, grid power and water • 125 miles from Anfield's Shootaring Canyon Mill • Existing 3,500 ft, 12' x 9' decline and portal from historical underground mining on Velvet property
ONGOING ACTIVITIES	• An updated Plan of Ops and environmental studies are being commissioned to capitalize on the advanced permitting and licensing work previously undertaken by Uranium One



CLASSIFICATION	TONS (KT)	URANIUM GRADE (% EU_3O_8)	CONTAINED URANIUM (MLBS U_3O_8)
M & I	811	0.29%	4,627
Inferred	87	0.32%	552

The PEA for Velvet-Wood/Slick Rock was authored by Douglas L. Beahm, P.E., P.G. Principal Engineer, Harold H. Hutson, P.E., P.G. and Carl D. Warren, P.E., P.G., of BRS Inc., Terence P. (Terry) McNulty, P.E., D. Sc., of T.P. McNulty and Associates Inc. (May 6, 2023). Mineral resources are not mineral reserves and do not have demonstrated economic viability in accordance with CIM standards. GT cut-off varies by locality from 0.25%-0.50%.

WEST SLOPE PROJECT

COLORADO

WEST SLOPE PROJECT

OWNERSHIP	• 100% owned by Anfield • Acquired from Cotter Corporation in 2018
LOCATION	• 9 DOE leases and adjacent lode mining claims covering 6,913 acres in Montrose and San Miguel Counties of SW Colorado
HISTORICAL	• Approximately 1.3 Mlbs of uranium and 6.6 Mlbs of vanadium produced historically from 1977-2006
INFRASTRUCTURE	• Historic adits, underground stopes, open pit, and affiliated infrastructure on site • Road and power access
NEXT STEPS	• Advance to a PEA on the four deposit areas with NI 43-101 resources • Commission updated resource estimates for the five historic resource areas through verification of historical data • Continue to target prospective brownfield properties, making use of abundant historical information in the region

CLASSIFICATION	TONS (KT)	URANIUM GRADE (% U_3O_8)	CONTAINED URANIUM (MLBS U_3O_8)	VANADIUM GRADE (% V_2O_5)	CONTAINED VANADIUM (MLBS V_2O_5)
Indicated	1,367	0.197%	5.4	-	-
Inferred	1,367	-	-	0.984%	26.9
Historic*	630	0.31%	3.9	1.59%	20.0

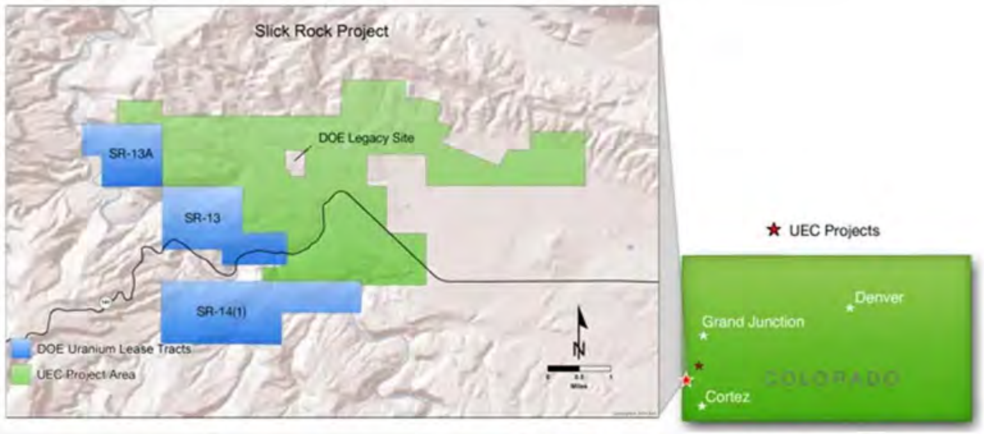
NI 43-101 resource estimate for the JD-6, JD-7, JD-8 and JD-9 properties, completed by BRS Inc. (effective March 2022); Historic resource estimate for the SR-11, SR-13A, SM-18 N, SM-18 S, LP-21 and CM-25 properties, completed by Behre Dolbear for Cotter Corporation (August 2007). Indicated and Inferred resources using GT cut-off of 0.1 ft% eU_3O_8; historic resources using cut-off of 0.05% U_3O_8.

SLICK ROCK PROJECT

COLORADO

SLICK ROCK PROJECT

OWNERSHIP	• 100% ownership of contiguous lease tracts
LOCATION	• San Miguel County, Colorado approximately 24 miles north of the town of Dove Creek
HISTORY	• The Slick Rock property produced uranium and vanadium from 1957 to 1983 via the Burro Mines
INFRASTRUCTURE	• Existing shafts, portals and working at site, with road and power access, and proximal location to an existing mill
RECENT NEWS	• PEA results returned positive economics (May 6, 2023)



CLASSIFICATION	TONS (KT)	URANIUM GRADE (% U_3O_8)	CONTAINED URANIUM (MLBS U_3O_8)	VANADIUM GRADE (% V_2O_5)	CONTAINED VANADIUM (MLBS V_2O_5)
Historic Inferred	1,760	0.224%	7.9	1.35%	47.1

The PEA for Velvet-Wood/Slick Rock was authored by Douglas L. Beahm, P.E., P.G. Principal Engineer, Harold H. Hutson, P.E., P.G. and Carl D. Warren, P.E., P.G., of BRS Inc., Terence P. (Terry) McNulty, P.E., D. Sc., of T.P. McNulty and Associates Inc. (May 6, 2023). Mineral resources are not mineral reserves and do not have demonstrated economic viability in accordance with CIM standards. GT cut-off varies by locality from 0.25%-0.50%.

PEER COMPARISON

FAVOURABLY SITUATED VS. US URANIUM PEER GROUP, AMPLIFIED BY AN INDUSTRY-LEADING VANADIUM RESOURCE BASE

		US URANIUM PEERS							
PEERS	**AEC**	**EFR**	**UEC**	**EU**	**URE**	**PEN**	**CUR**	**LAM**	**WUC**
MARKET CAP (C$M)	$85	$1,712	$2,586	$606	$525	$131	$199	$126	$71
EV (C$M)	$84	$1,677	$2,569	$666	$460	$110	$189	$123	$65
U_3O_8 RESOURCES (Mlbs)									
M&I	10.5	66.7	198.4	44.7	20.7	15.8	6.6	43.2	-
Inferred	8.5	38.2	67.7	6.1	6.6	37.8	2.2	74.9	-
Historic	27.7	15.2	98.5	68.4	13.8	-	260.5	-	55.2
V_2O_5 RESOURCES (Mlbs)									
Inferred	89.1	17.7	-	-	-	-	-	-	-
Historic	19.5	-	-	-	-	-	90.7	-	28.2
100% US ASSETS	✓	✓	✗	✓	✓	✓	✗	✗	✓
U_3O_8 FOCUSED	✓	✗	✓	✓	✓	✓	✓	✓	✓
V_2O_5 BY-PRODUCT	✓	✓	✗	✗	✗	✗	✓	✗	✓
PRODUCTION FACILITIES	✓	✓	✓	✓	✓	✗	✗	✗	✗

As of August 18, 2023; peer resources include publicly disclosed historic resources

MANAGEMENT + DIRECTORS

COREY DIAS
CO-FOUNDER, CEO AND DIRECTOR

Co-Founder of Anfield Energy. 20 years of capital markets experience. Former equity research analyst, fund manager and strategy consultant with CIBC, Fortress Investment Group and Monitor Group, respectively

LAARA SHAFFER
CFO, DIRECTOR

Currently, Laara Shaffer occupies the position of Chief Financial Officer & Secretary of Anfield Energy, Inc. Ms. Shaffer is also on the board of Pro-Tech Venture Corp. and Aquilla Energy Corp.

With a diverse career spanning leadership positions including President, CEO, and Director in organizations like Montello Resources Ltd., Oronova Energy, Inc., and Passport Potash, Inc., she has consistently demonstrated a commitment to driving success and growth in the corporate arena.

KEN MUSHINSKI
CHAIRMAN

33 years of nuclear-related experience at General Atomics Corporation and its various subsidiaries, including Cotter Corporation, Quasar Resources and the Honeywell/General Atomics ConverDyn partnership

JOSHUA BLEAK
CO-FOUNDER AND DIRECTOR

Co-Founder of Anfield Energy. 4th generation miner from Arizona with extensive resource development experience in southwestern US; former President of American Energy Fields, a junior uranium company

MANAGEMENT + DIRECTORS

DON FALCONER
DIRECTOR

35 years experience in uranium and nuclear utility sectors in both public and private spheres, including senior management and Director positions with Uranium One, Southern Cross, Energy Fuels, AusAmerican Mining and Ontario Hydro

STEPHEN LUNSFORD
DIRECTOR

40 years experience as senior geologist in all stages of mine exploration and development; formerly with Cameco

EUGENE SPIERING
ENCORE ENERGY'S APPOINTE, DIRECTOR

Eugene Spiering is an accomplished exploration geologist with more than 30 years of international experience in mineral exploration and senior-level project management across various regions, including the Western United States, South America, and Europe.

He has made significant contributions to the industry, having played integral roles in the discovery and development of several notable mining projects.

JOHN ECKERSLEY
DIRECTOR

U.S.-based attorney with 30 years of experience, including 10 years with publicly-traded companies

APPENDIX

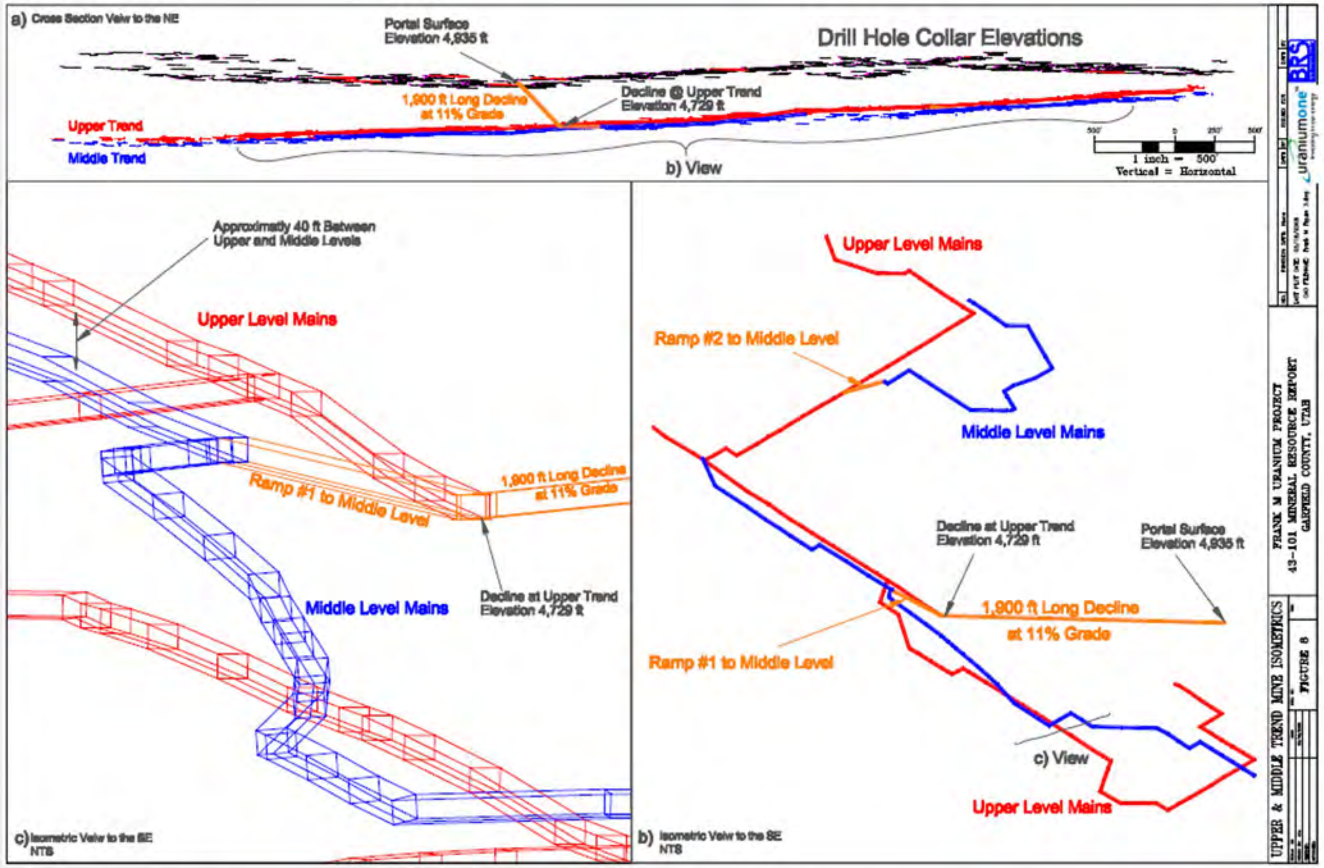
OTHER REGIONAL ASSETS

FRANK M DEPOSIT (100% INTEREST)

- Located ~12 km north of the Shootaring Canyon Mill
- Historic NI 43-101 resource estimate (2008) containing 2.3 Mlbs U_3O_8 at 0.101% U_3O_8

FINDLAY TANK BRECCIA PIPES (100% INTEREST)

- Located in Majave County in northern Arizona
- High-grade breccia pipe deposits
- Historic NI 43-101 resource estimate (2008) containing 954 klbs U_3O_8 at 0.226% U_3O_8



HISTORIC RESOURCES	TONS (KT)	URANIUM GRADE (% EU_3O_8)	CONTAINED URANIUM (MLBS U_3O_8)
Frank M	1,137	0.101%	2.3
Findlay Tank	211	0.226%	1.0

Historic Technical Report for Frank M, prepared for Uranium One Americas, was authored by Douglas L. Beahm, P.E., P.G. Principal Engineer of BRS Inc., and Andrew C. Anderson, P.E., P.G. Senior Engineer/Geologist of BRS Inc., dated June 10, 2008. Historic Technical Report for Findlay Tank, prepared for Uranium One Americas, was authored by Douglas L. Beahm, P.E., P.G. Principal Engineer of BRS Inc., dated October 2, 2008.

Frank M historic resource used a GT cut-off of 0.25%. Findlay Tank historic resource used a grade cut-off of 0.05% eU_3O_8.

ANFIELD Energy

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Exhibit 22

U.S. Energy Information Administration

Table S1a. Uranium purchased by owners and operators of U.S. civilian nuclear power reactors, 2002–2023
million pounds U_3O_8 equivalent

Delivery Year	Total purchased	Purchased from U.S. producers	Purchased from U.S. brokers and traders	Purchased from other owners and operators of U.S. civilian nuclear power reactors, other U.S. suppliers, (and U.S. government for 2007)[1]	Purchased from foreign suppliers	U.S.-origin uranium	Foreign-origin uranium	Spot contracts[2]	Short, medium, and long-term contracts[3]
2002	**52.7**	1.5	13.4	5.7	**32.2**	**6.2**	**46.5**	**8.6**	**41.4**
2003	**56.6**	0.6	10.5	8.3	**37.2**	**10.2**	**46.4**	**8.2**	**46.7**
2004	**64.1**	0	13.2	12.2	**38.7**	**12.3**	**51.8**	**9.2**	**53.3**
2005	**65.7**	W	10.4	W	**39.4**	**11.0**	**54.7**	**6.9**	**58.8**
2006	**66.5**	0	13.9	12.6	**40.0**	**10.8**	**55.7**	**6.3**	**59.4**
2007	**51.0**	0	9.8	7.6	**33.5**	**4.0**	**47.0**	**6.6**	**43.7**
2008	**53.4**	0.6	9.4	6.3	**37.2**	**7.7**	**45.6**	**8.7**	**42.8**
2009	**49.8**	W	11.1	W	**36.8**	**7.1**	**42.8**	**8.1**	**41.0**
2010	**46.6**	0.4	11.7	1.9	**32.6**	**3.7**	**42.9**	**8.2**	**37.9**
2011	**54.8**	0.6	14.8	1.1	**38.4**	**5.2**	**49.6**	**12.0**	**42.3**
2012	**57.5**	W	11.5	W	**37.6**	**9.8**	**47.7**	**8.1**	**48.9**
2013	**57.4**	W	12.8	W	**37.4**	**9.5**	**47.9**	**11.3**	**46.1**
2014	**53.3**	W	17.1	W	**34.4**	**3.3**	**50.0**	**14.5**	**38.8**
2015	**56.5**	W	13.9	W	**38.2**	**3.4**	**53.1**	**11.3**	**43.2**
2016	**50.6**	W	7.9	W	**39.5**	**5.4**	**45.2**	**10.6**	**37.0**
2017	**43.0**	W	4.5	W	**34.4**	**2.9**	**40.1**	**6.2**	**36.6**
2018	**40.3**	W	3.9	W	**33.0**	**3.9**	**36.4**	**6.5**	**33.4**
2019	**48.3**	W	4.4	W	**39.2**	**W**	**W**	**10.5**	**37.8**
2020	**48.9**	W	6.4	W	**38.4**	**W**	**W**	**11.8**	**37.0**
2021	**46.7**	1.7	3.3	0.0	**41.6**	**2.5**	**44.3**	**9.0**	**37.8**
2022	**40.5**	W	W	0.0	**38.0**	**W**	**W**	**5.9**	**34.6**
2023	**51.6**	W	W	W	**49.6**	**2.4**	**49.2**	**7.7**	**43.9**

- - = Not applicable.
W = Data withheld to avoid disclosure of individual company data.
NA = Not available.
[1]Includes purchases between owners and operators of U.S. civilian nuclear power reactors along with purchases from other U.S. suppliers which are U.S. converters, enrichers, and fabricators.
[2]Spot Contract: A one-time delivery (usually) of the entire contract to occur within one year of contract execution (signed date).
[3]Short, Medium, and Long-Term Contracts: One or more deliveries to occur after a year following contract execution (signed date).
Notes: *Other U.S. Suppliers* are U.S. converters, enrichers, and fabricators. Totals may not equal sum of components because of independent rounding.
Data Sources: U.S. Energy Information Administration: *Uranium Industry Annual*, Tables 10, 11 and 16, 2002. Form EIA-858, *Uranium Marketing Annual Survey*, 2003-2023

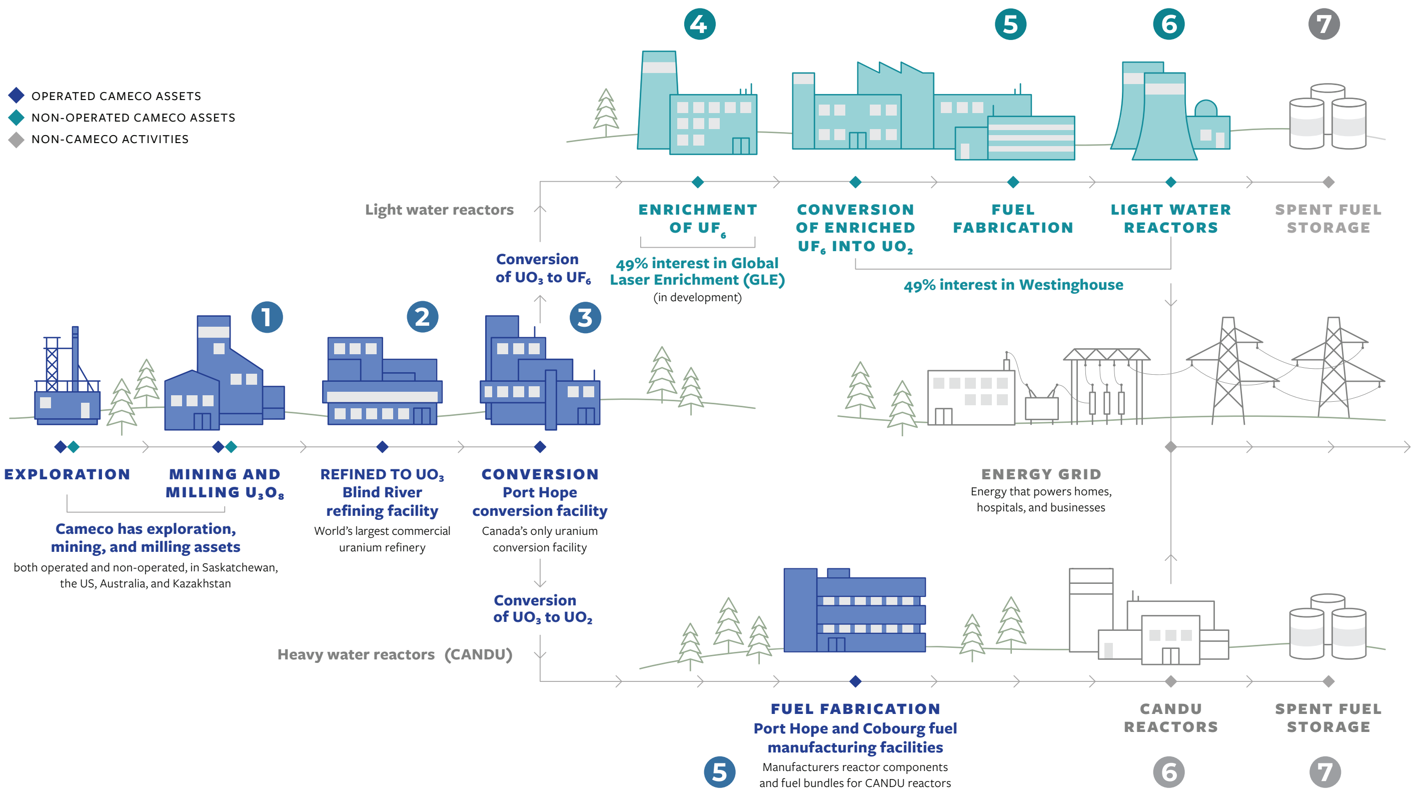
Exhibit 23

Powering a Secure Energy Future

2024
Annual Report

Cameco

Nuclear Fuel Cycle



1 Mining & Milling

Once an orebody is discovered and defined by exploration, there are three common ways to mine uranium, depending on the depth of the orebody and the deposit's geological characteristics:

- **Open pit mining** is used if the ore is near the surface. The ore is usually mined using drilling and blasting.
- **Underground mining** is used if the ore is too deep to make open pit mining economical. Tunnels and shafts provide access to the ore.
- **In situ recovery (ISR)** does not require large scale excavation. Instead, holes are drilled into the ore and a solution is used to dissolve the uranium. The solution is pumped to the surface where the uranium is recovered.

Ore from open pit and underground mines is processed to extract the uranium and package it as a powder typically referred to as uranium concentrates (U_30_8) or yellowcake. The leftover processed rock and other solid waste (tailings) is placed in an engineered tailings facility.

2 Refining

Refining removes impurities from the uranium concentrate and changes its chemical form to uranium trioxide (UO_3).

3 Conversion

For light water reactors, the UO_3 is converted to uranium hexafluoride (UF_6) gas to prepare it for enrichment. For heavy water reactors, like the CANDU reactors, the UO_3 is converted into powdered uranium dioxide (UO_2).

4 Enrichment

Uranium is made up of two main isotopes: U-238 and U-235. Only U-235, which makes up 0.7% of natural uranium, is involved in the nuclear fission reaction and most of the world's reactors require an enriched level of U-235.

The enrichment process increases the concentration of U-235, with most of the existing global reactor fleet requiring between 3% and 5%. However, to allow for extended refueling cycles and for some new and advanced reactor designs, higher levels of enrichment may be required.

Enriched gas is then converted to powdered UO_2.

5 Fuel fabrication

Natural or enriched UO_2 is pressed into pellets, which are baked at a high temperature. These are packed into zircaloy or stainless steel tubes, sealed and then assembled into fuel bundles that are specific to each reactor design.

6 Reactor Services (LWR/HWR)

Nuclear reactors are used to generate electricity. U-235 atoms in the reactor fuel fission, creating heat that generated steam to drive turbines. Once a light water reactor is operating, it needs to be inspected and maintained every 18-24 months, at which time a portion of the fuel bundles must also be replaced to maximize efficiency. Heavy water reactors (CANDU) are continually refuelled, but must be refurbished after several decades of service.

7 Spent fuel management

The majority of spent fuel is safely stored at the reactor site. A small amount of spent fuel is reprocessed. The reprocessed fuel is used in some European and Japanese reactors.

Cameco

Management's discussion and analysis

February 20, 2025

This management's discussion and analysis (MD&A) includes information that will help you understand management's perspective of our audited consolidated financial statements (financial statements) and notes for the year ended December 31, 2024. The information is based on what we knew as of February 19, 2025.

We encourage you to read our audited consolidated financial statements and notes as you review this MD&A. You can find more information about Cameco, including our financial statements and our most recent annual information form, on our website at cameco.com, on SEDAR+ at www.sedarplus.ca, or on EDGAR at www.sec.gov. You should also read our annual information form before making an investment decision about our securities.

The financial information in this MD&A and in our financial statements and notes is prepared according to International Financial Reporting Standards (IFRS), unless otherwise indicated.

Unless we have specified otherwise, all dollar amounts are in Canadian dollars.

Throughout this document, the terms we, us, our, the Company and Cameco mean Cameco Corporation and its subsidiaries, unless otherwise indicated.

2024 performance highlights

In 2024, we revised our calculation of adjusted net earnings to adjust for unrealized foreign exchange gains and losses as well as for share-based compensation because it better reflects how we assess our operational performance. We have restated comparative periods to reflect this change. See non-IFRS measures starting on page 65 for more information.

Financial performance

HIGHLIGHTS DECEMBER 31 ($ MILLIONS EXCEPT WHERE INDICATED)	2024	2023	CHANGE
Revenue	**3,136**	2,588	21%
Gross profit	**783**	562	39%
Net earnings attributable to equity holders	**172**	361	(52)%
$ per common share (diluted)	**0.39**	0.83	(52)%
Adjusted net earnings (non-IFRS, see page 65)	**292**	383	(24)%
$ per common share (adjusted and diluted)	**0.67**	0.88	(24)%
Adjusted EBITDA (non-IFRS, see page 65)	**1,531**	884	73%
Cash provided by operations	**905**	688	32%

Net earnings attributable to equity holders (net earnings) and adjusted net earnings were lower in 2024 compared to 2023 primarily due to the impact of purchase accounting on the full year results of Westinghouse. As a result, we believe adjusted EBITDA is a better measure to assess our operating performance. See *2024 consolidated financial results* beginning on page 38 for more information. Of note, we:

- increased adjusted EBITDA by 73% as a result of improving results in our uranium segment due to the return to our tier-one production levels, as well as full year results from Westinghouse, our share of its adjusted EBITDA being $483 million for 2024. See *non-IFRS measures* starting on page 65 for more information.
- generated $905 million in cash from operations
- received a cash dividend of $129 million (US), net of withholdings, from JV Inkai
- received $49 million (US) in February 2025, which represents our share of a $100 million (US) distribution paid by Westinghouse
- successfully refinanced $500 million in unsecured debentures that matured in 2024. The refinanced debt now matures in 2031 with credit spreads reflective of a higher credit rating than we currently have been assigned
- prioritized repayment of $400 million (US) of the $600 million (US) term loan utilized to finance the acquisition of Westinghouse, reducing total debt to $1.3 billion. The remaining $200 million (US) was repaid in January 2025, extinguishing the term loan. See *Liquidity* starting on page 50 for more information.
- increased our annual dividend to $0.16 per common share in 2024, with a plan to increase the dividend to at least $0.24 per common share over time. See *Return* for more details.

Our segment updates and other fuel cycle investment updates

In our uranium segment, we continued to execute our strategy, further ramping up our tier-one assets which had a positive impact on our operations. Of note in 2024, we:

- delivered 33.6 million pounds of uranium in alignment with the commitments under our contract portfolio
- produced 16.9 million pounds (100% basis) at Cigar Lake. Production did not meet our expectations due to a lower production rate at Orano's McClean Lake mill.
- produced 20.3 million pounds (100% basis) at McArthur River/Key Lake, setting a new production record for a uranium mining operation anywhere in the world, due in large part to off-cycle investments in automation, digitization and optimization projects at Key Lake.
- purchased 11.0 million pounds of uranium, including our spot purchases and committed purchase volumes (including JV Inkai purchases)
- received the final 1.2 million pounds of our share of JV Inkai's 2023 production, as well as 2.7 million pounds of our total share of JV Inkai's 2024 production. The remainder of our share of 2024 production, about 0.9 million pounds, is being

stored at JV Inkai for future delivery in order to optimize transportation and delivery costs. The timing of future deliveries is uncertain.
- maintained Rabbit Lake and US ISR operations in care and maintenance

In 2024, in our fuel services segment, we:
- delivered 12.1 million kgU under contract
- produced 13.5 million kgU, including 10.8 million kgU of UF_6

See *Operations and projects* beginning on page 73 for more information.

HIGHLIGHTS			2024	2023	CHANGE
Uranium	Production volume (million lbs)		**23.4**	17.6	33%
	Sales volume (million lbs)		**33.6**	32.0	5%
	Average realized price[1]	($US/lb)	**58.34**	49.76	17%
		($Cdn/lb)	**79.70**	67.31	18%
	Revenue ($ millions)		**2,677**	2,153	24%
	Gross profit ($ millions)		**681**	445	53%
	Earnings before income taxes		**904**	606	49%
	Adjusted EBITDA (non-IFRS, see page 65)		**1,179**	835	41%
Fuel services	Production volume (million kgU)		**13.5**	13.3	2%
	Sales volume (million kgU)		**12.1**	12.0	1%
	Average realized price [2]	($Cdn/kgU)	**37.87**	35.61	6%
	Revenue ($ millions)		**459**	426	8%
	Earnings before income taxes		**108**	129	(16)%
	Adjusted EBITDA (non-IFRS, see page 65)		**145**	164	(12)%
Westinghouse[3]	Revenue ($ millions)		**2,892**	521	>100%
(our share)	Net loss		**(218)**	(24)	>100%
	Adjusted EBITDA (non-IFRS, see page 65)		**483**	101	>100%

[1] Uranium average realized price is calculated as the revenue from sales of uranium concentrate, transportation and storage fees divided by the volume of uranium concentrates sold.
[2] Fuel services average realized price is calculated as revenue from the sale of conversion and fabrication services, including fuel bundles and reactor components, transportation and storage fees divided by the volumes sold.
[3] This table includes comparative results for the period beginning on the date of acquisition until the end of 2023

It was another positive year for the nuclear energy industry. Demand for nuclear power, including support for existing reactors, continues to grow, with a focus on energy security and national security amid continued global geopolitical uncertainty. We believe nuclear energy is in durable growth mode, and as we see the growth translate into contracts, we too will be back in durable growth mode. This growth will be sought in the same manner as we approach all aspects of our business; strategic, deliberate, disciplined and responsible and with a focus on generating full-cycle value.

Strong fourth quarter results in the uranium and Westinghouse segments provided a boost to annual results, as expected. Net earnings were $135 million for the quarter and $172 million for the year compared to $80 million for the quarter and $361 for the year in 2023, while adjusted net earnings were $157 million for the quarter and $292 million for the year compared to $108 million for the quarter and $383 million for the year in 2023. The 2024 annual results were lower compared to 2023 primarily due to the impact of purchase accounting on the full year results of Westinghouse. We use adjusted EBITDA to assess our operational performance. Full year adjusted EBITDA increased by approximately $647 million to $1.5 billion compared to $884 million in 2023 mainly due to the contributions from the uranium segment, reflective of a return to our tier-one production levels and an improving price environment, as well as the benefit from a full year of our Westinghouse investment, which was acquired in November 2023.

In our uranium segment, despite muted contracting volumes for the industry as utilities focused first on securing enrichment and conversion, we continued to negotiate off-market contracts and add to our long-term portfolio. After delivering our 2024 sales, the long-term portfolio now totals about 220 million pounds, representing about 25% of our current reserve and resource base and retaining exposure to the improving demand from our customers as they look to secure their long-term needs. We continue to have a large and growing pipeline of uranium business under discussion. Our focus remains on obtaining market-related pricing mechanisms that benefit from a constructive price environment, while also providing adequate downside protection. We are being strategically patient in our discussions to maximize value in our contract portfolio and to maintain exposure to higher prices with unencumbered future productive capacity. In addition, with strong demand and pricing at historic highs in the UF_6 conversion market, we were successful in adding new long-term contracts that bring our total contracted volumes to about 85 million kgU of UF_6 that will underpin our fuel services operations for years to come.

Cameco has more than 35 years of experience in this market, and we have designed our strategy of full-cycle value capture to be resilient. Given the nature of our contracts, we have good visibility into when and where we need to deliver material, and we have put in place a number of tools that allow us to self-manage risk.

We have built a strong reputation as a proven and reliable supplier, with a diversified production portfolio that provides us with the flexibility to work with our customers to ensure they maintain access to our reliable supplies to satisfy their ongoing fuel requirements. In addition to our production, we can source material from market purchases today, and while these purchases would be more expensive than our production, our strategy positions us to benefit from added demand for nuclear fuel supplies and services. We have exposure to higher prices under the market-related contracts in our long-term portfolio and a pipeline of contracting discussions underway, which we expect will also benefit from the increased focus on securing access to scarce supplies and generate long-term value for Cameco. Also, we do not have to buy every pound in the spot market. We can source from inventory, to be replaced by production or purchases later. Further, we have the ability to pull forward long-term purchase arrangements that we put in place in a much lower-price environment, and with licensed storage facilities, we have secured the ability to borrow product under the terms of some of our storage agreements. See *Managing our Contract Commitments* on page 27 for more information on our sourcing options.

The tailwinds that are expected to benefit our core uranium and fuel services businesses are also presenting significant future growth opportunities for Westinghouse, which we own with our partner Brookfield Renewable Partners (Brookfield) (Cameco's share is 49%). In 2024, we saw the continued advancement of AP1000® new build opportunities in Poland, Bulgaria, Ukraine and Slovenia. In early 2025, Westinghouse also announced a settlement agreement in its technology and export dispute with Korea Electric Power Corporation and Korea Hydro & Nuclear Power Co., Ltd. (KEPCO and KHNP), which resolves the dispute and establishes a framework for additional deployments outside of South Korea, to the mutual and material benefit of Westinghouse, KEPCO and KHNP. See *Westinghouse Electric Company* starting on page 98 for more information.

Thanks to our disciplined strategy, our balance sheet is strong, and we expect it will enable us to continue executing our strategy while self-managing risk, including risks related to global macro-economic uncertainty and volatility, and uncertain trade policy decisions. As of December 31, 2024, we had $600 million in cash and cash equivalents with $1.3 billion in total debt. In addition, we have a $1.0 billion undrawn credit facility.

In the current environment, we believe the risk to uranium supply is greater than the risk to uranium demand and expect it will create a renewed focus on ensuring availability of long-term supply to fuel nuclear reactors.

We will continue to align our production with our contract portfolio and market opportunities, demonstrating that we continue to responsibly manage our supply in accordance with our customers' needs.

We will continue to look for opportunities to improve operational effectiveness, to improve our safety performance and reduce our impact on the environment, including through the use of digital and automation technologies to allow us to operate our assets with more flexibility and efficiency. This is key to our ability to continue to align our production decisions with our contract portfolio commitments and opportunities. With a solid base of contracts to underpin our tier-one productive capacity, and a growing contracting pipeline we expect we will continue to generate strong financial performance.

As we execute on our strategy, we will continue to focus on protecting the health and safety of our employees, delivering our products safely and responsibly and addressing the risks and opportunities that we believe will make our business sustainable and will build long-term value.

Industry prices

	2024	2023	CHANGE
Uranium ($US/lb U_3O_8)[1]			
Average annual spot market price	**85.14**	62.51	36%
Average annual long-term price	**78.88**	58.20	36%
Fuel services ($US/kgU as UF_6)[1]			
Average annual spot market price			
North America	**68.29**	41.23	66%
Europe	**68.21**	41.23	65%
Average annual long-term price			
North America	**40.57**	30.55	33%
Europe	**40.47**	30.55	32%
Note: the industry does not publish UO_2 prices.			

[1] Average of prices reported by TradeTech and UxC, LLC (UxC)

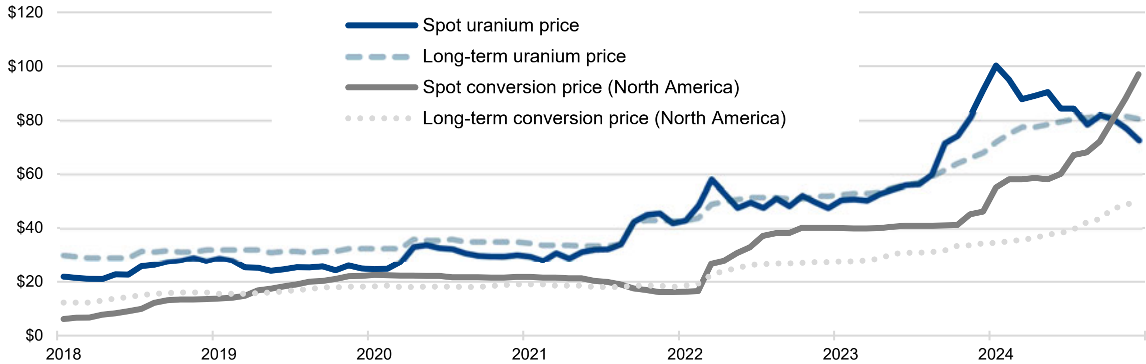
On the spot market, where purchases call for delivery within one year, the volume reported by UxC for 2024 decreased to 46 million pounds U_3O_8 equivalent, compared to 57 million pounds U_3O_8 equivalent in 2023. In 2024, total spot purchases by producers, junior uranium companies, financial funds and intermediaries was approximately 40 million pounds U_3O_8 equivalent, compared to approximately 43 million pounds U_3O_8 equivalent in 2023; in 2024, these purchases represented over 85% of spot market purchases compared to over 76% in 2023. In 2024, the uranium spot price ranged from a month-end high of $100.25 (US) per pound to a month-end low of $72.63 (US), averaging $85.14 (US) for the year. This average was up $22.63 (US) per pound, or 36%, compared to the 2023 average.

Long-term contracts generally call for deliveries to begin more than two years after the contract is finalized, and use a number of pricing formulas, including base-escalated prices set at time of contracting and escalated over the term of the contract, and market referenced prices (spot and long-term indicators) determined near the time of delivery, which also often include floor prices and ceiling prices that are also escalated to time of delivery. The volume of long-term contracting reported by UxC for 2024 was about 119 million pounds U_3O_8 equivalent, down from about 161 million pounds U_3O_8 equivalent in 2023. The contracting volume in 2023 was higher due to significant non-US utilities diversifying away from Russian supply, including our contracts with Ukraine and Bulgaria, one of which totaled over 40 million pounds. The lower long-term uranium volumes reported in 2024 can be attributed in part to US utilities awaiting clarity on implementation of the Russian uranium import ban, the US waiver process, and Russian export restraints, although requests for proposals from utilities are continuing alongside requests for direct off-market negotiations.

The average reported long-term price at the end of the year was $80.50 (US) per pound, up $12.50 (US) from the end of 2023. During the year, the uranium long-term price steadily increased from a month-end low of $72.00 (US) per pound in January to a high of $81.50 (US) per pound in November, averaging $78.88 (US) for the year.

With increased demand for western conversion services, pricing in both North America and Europe continues to be strong. At the end of 2024, the average reported spot price for North American delivery reached a record high of $97.00 (US) per kilogram uranium as UF_6 (US/kgU as UF_6), up $51.00 (US) from the end of 2023. Long-term UF_6 conversion prices for North American delivery also reached a record high and finished 2024 at $50.00 (US/kgU as UF_6), up $15.75 (US) from the end of 2023.

URANIUM (US$/lb U_3O_8) AND CONVERSION (US$/kgU UF_6) PRICES



Source: Average of prices reported from TradeTech and UxC