Energy development water needs assessment and water supply alternatives analysis

Yampa River Basin Roundtable Meeting

July 21, 2010



Phase I Oil Shale Industry Production Scenarios

Level of Development – Oil Shale

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	R & D	None	None
Mid-term (2018 – 2035)	None	Surface: 50,000 bbl/day In situ: 25,000 bbl/day	Surface: 50,000 bbl/day In-situ: 500,000 bbl/day
Long-term (2036 – 2050)	None	Surface: 50,000 bbl/day In-situ: 150,000 bbl/day	Surface: 50,000 bbl/day In-situ: 1,500,000 bbl/day

Phase II Timeframe Refinements

- Phase I timeframes unrealistically short
- Use Athabasca oil sands as a reasonable analog to development of an oil shale industry in the Piceance basin
- Initial field demonstration of technical feasibility for one or more in situ technologies would occur by 2015
  - initial technical feasibility of above-ground retorting has likely already been established
- Initial commercial production would occur 20 years later (compared to the 17-year period prior to development of first commercial production at the Athabasca oil sands)

Evaluation of Scenarios for Piceance Basin Oil Shale Industry

	Timeframe for Development	
	Phase I	Projected Scenario
Field demonstration of technical feasibility		2015
Initial commercial production, 50,000 barrels/day		2035
550,000 barrels/day	2018 – 2035	2053 - 2060
1,550,000 barrels/day	2036 – 2050	2061 - 2071

Planning Scenario

- Sub-committee decided to use a “build-out” scenario
- Adopted the High, Long-term scenario from Phase I
  - 1,500,000 bbl/day in situ
  - 50,000 bbl/day above-ground

Oil Shale Development
Direct Water Use

- Construction/Pre-production
- Electrical Energy
  - Assumed use of Combined Cycle Gas Turbines near production
  - Use of coal-fired thermal generation is not very likely
- Production
  - Assumed that by-product water produced by retorting would be treated and used for process purposes, thus offsetting some water needs.
- Reclamation
- Spent Shale Disposal
- Upgrading
  - Evaluated several alternative assumptions regarding the level of water use for upgrading and its location
  - Upgrading might be done locally or outside the study area.

Oil Shale Development
Direct Water Use Estimates (bbl/bbl)

	In-situ Retorting		Above-Ground Retorting	
	Low	High	Low	High
Construction/Pre-production	0.02	0.16	0.01	0.07
Electrical Energy	0.41	1.00	0.17	0.26
Production			0.47	0.47
Reclamation	0.45	0.54	0.02	0.17
Spent Shale Disposal			0.80	1.60
Upgrading	0.57	1.60	0.60	1.60

Estimates of Water Co-Produced when Retorting Oil Shale (bbl/bbl)

In-situ Retorting	Above-Ground Retorting
0.80	0.30

Oil Shale Development
Indirect Water Use

- Water required to support population growth and economic activity due to oil shale development
- Consistency with IBCC process – employment/population estimates from Harvey Economics
- Will be refined in Phase II to specific areas:
  - Garfield County
  - Mesa County
  - Rio Blanco County

Regional Employment Estimates

Process	Employment	Percent of Employment
In situ	14,375	84%
Above-Ground	1,920	11%
Energy generation	800	5%
Total Oil Shale	17,095	100%

Source: Harvey Economics, 2010; Year 32

Oil Shale Development
Indirect Water Use Estimates

- Assumptions:
  - Direct workforce water use: 100 gallons per-capita per day (gpcd)
  - Indirect workforce water use: 200 gpcd
  - Energy generation Direct workforce: 200 gpcd
    - Assumed to be living off-site
- Water required for electricity generation to support population growth not included
  - Assumed to come from the grid

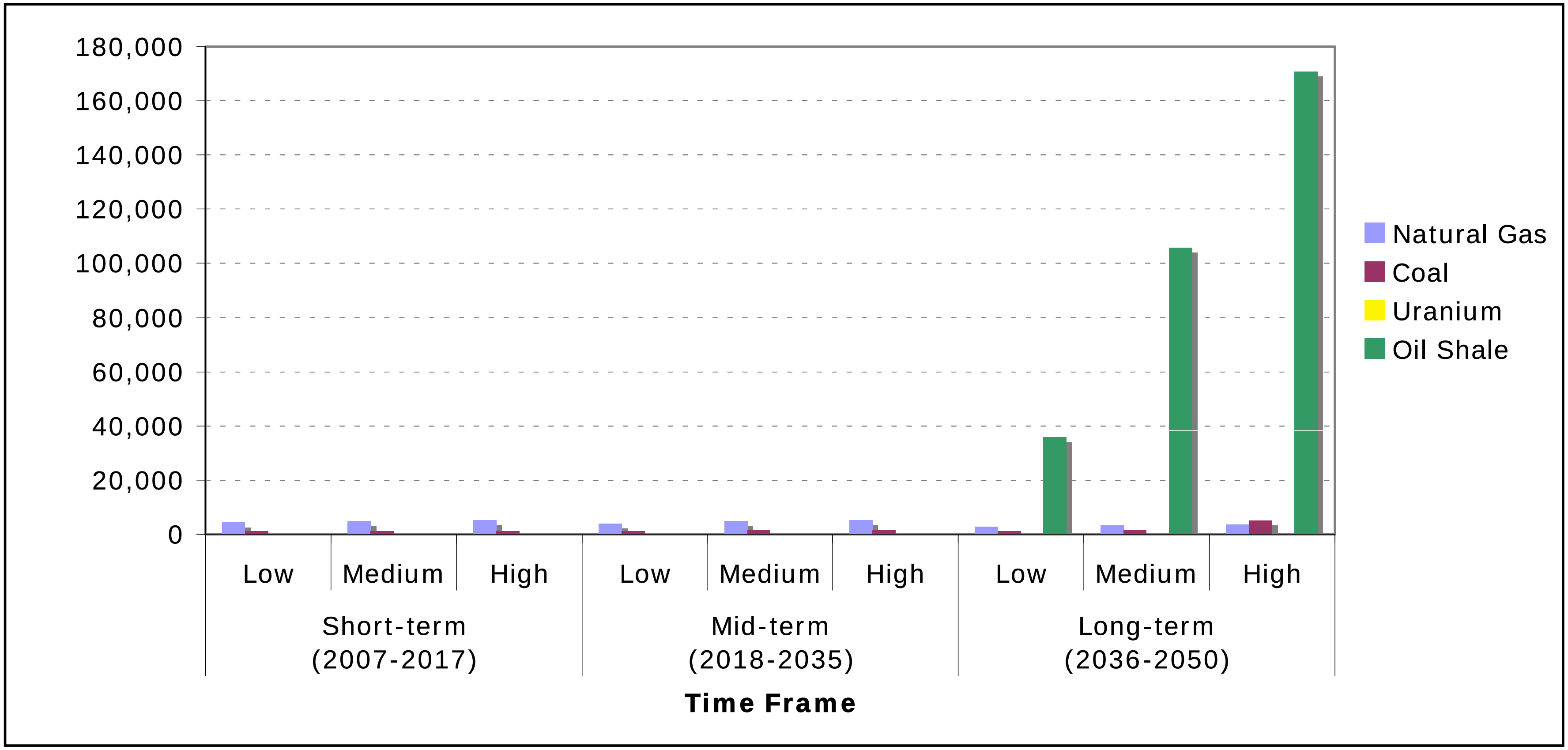
Oil Shale Development
Indirect Water Use Estimates

	In-situ Retorting		Above-Ground Retorting	
	bbl/bbl	acre-feet per year	bbl/bbl	acre-feet per year
Construction and Production	0.11	7,800	0.42	990
Electrical Energy	0.007	490	0.002	4.9

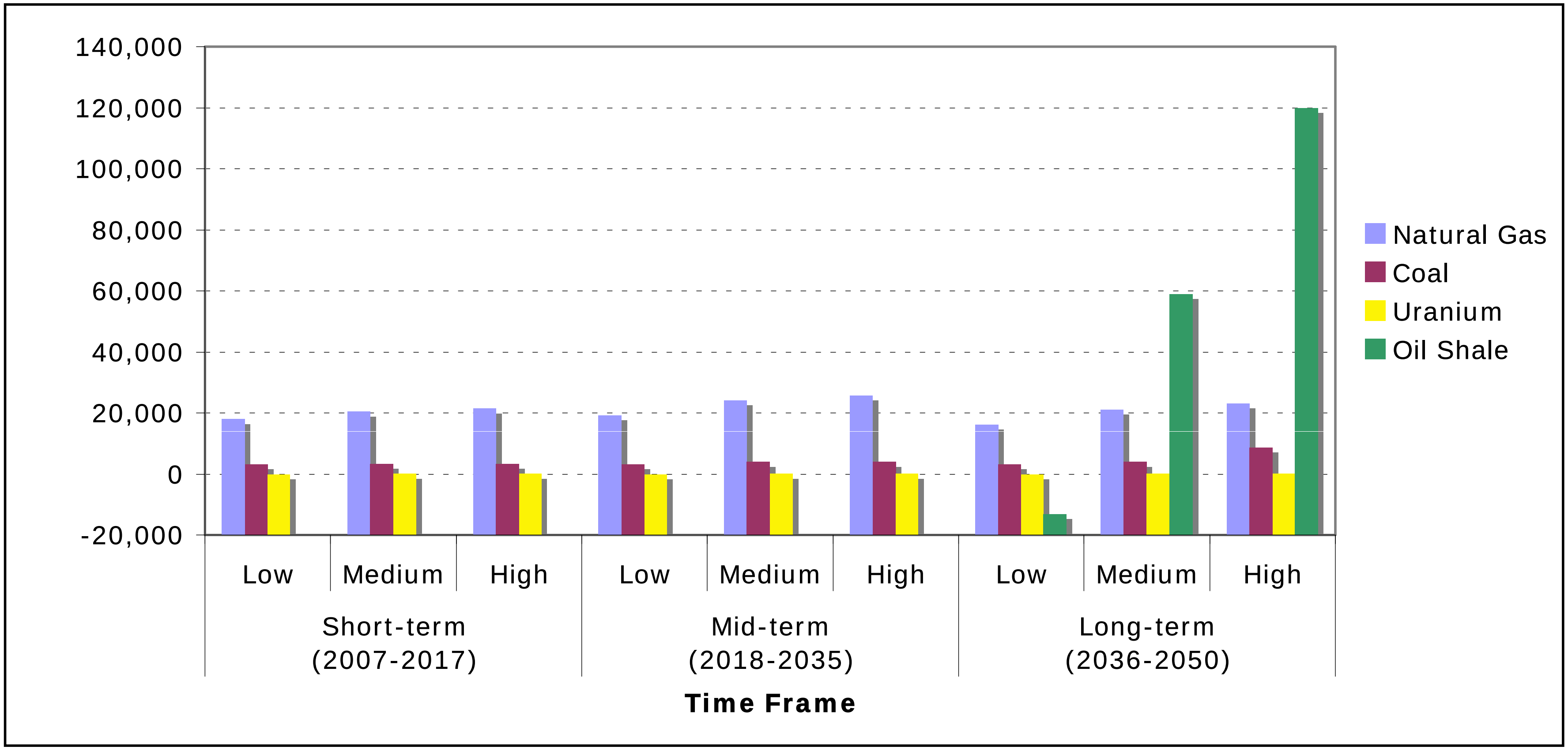
Energy Water Use Scenarios

- Production Scenarios and Water Demands for Natural Gas, Uranium and Coal development are the same as in Phase I
- Production Scenarios and Water Demands for Oil shale development are being refined in Phase II

Summary of Phase II Direct Water Demands



Summary of Phase II Total Water Demands



In Situ Industry Configurations and Total Unit Water Use

In Situ Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
IS-1	Down-hole combustion heating off-site upgrading. Low estimates.	-0.22	Without energy direct use or use by energy workforce; no upgrading use.
IS-2	Down-hole combustion heating, off-site upgrading. High estimates.	0.01	Without energy direct use or use by energy workforce.
IS-3	Shell in situ conversion process (ICP), off-site upgrading. Low estimates.	0.20	Without energy direct use or use by energy workforce; no upgrading use.
IS-4	Shell ICP, on-site upgrading. Low estimates.	0.77	Based on low estimates of electricity use and other process water uses. ICP will likely require less intensive upgrading.
IS-5	Shell ICP, off-site upgrading. High estimates.	1.02	Based on high estimates of electricity use and other process water uses.
IS-6	Down-hole combustion heating on-site upgrading. High estimates.	1.61	Based on high estimates of process water uses. No electrical heating. Combustion-based processes are more likely to require more upgrading. Highest combustion value.
IS-7	Shell ICP, on-site upgrading. High process, low upgrading.	1.59	Uses low estimate of upgrading, as ICP process is more likely to require less upgrading. Otherwise uses high estimates. Highest ICP value.

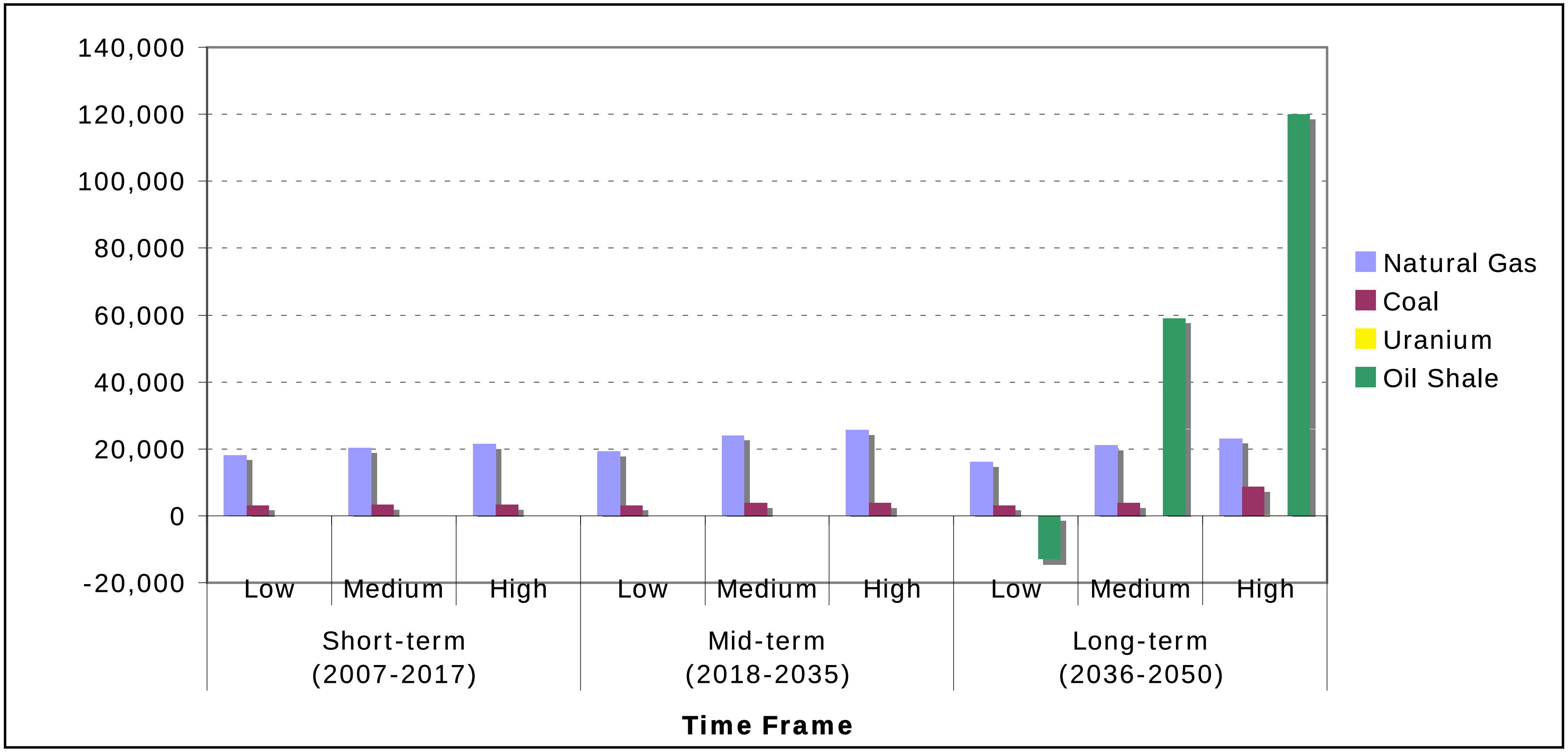
Above-Ground Industry Configurations and Total Unit Water Use

Above-Ground Scenario	Scenario Description	Unit Use (bbl/bbl)	Comments
AG-1	Off-site electricity, off-site upgrading. Low estimates	1.41	Seems a likely possibility, if above-ground product is compatible with down-hole in situ product; small electricity demands can be met from grid. Use with down-hole in-situ.
AG-2	Off-site electricity, on-site upgrading. Low estimates	2.01	Likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Use with ICP.
AG-3	On-site electricity, on-site upgrading. Low estimates	2.18	Use co-produced gas for on-site combined cycle gas turbine (CCGT). Likely that above-ground retort product will require more intensive upgrading, so this estimate may be low. Use with ICP.
AG-4	Off-site electricity, off-site upgrading. High estimates	2.43	Seems a likely possibility, if Above-Ground product is compatible with down-hole in situ; small electricity demands can be from grid. Use with down-hole in situ method.
AG-5	Off-site electricity, on-site upgrading. High estimates	4.03	Seems a likely possibility with ICP in situ, since the small above-ground production might require on-site upgrading; small electricity demands can be from grid. Use with ICP.
AG-6	On-site electricity, on-site upgrading High estimates,	4.29	Use co-produced gas for on-site CCGT. Use with ICP.

Total Water Use for Selected Scenarios

Scenario	Unit Use (bbl/bbl)	Industry Water Use, acre-feet/year		
		Low	Medium	High
IS-1	-0.22	-16,000		
IS-4	0.77		54,000	
IS-7	1.59			110,000
AG-1	1.41	3,300		
AG-3	2.18		5,100	
AG-6	4.29			10,000
Total		-13,000	59,000	120,000

Summary of Phase II Total Water Demands



Natural Gas Industry Production Scenarios

Level of Development – Natural Gas

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	Average drilling rate ≈ 1,800 wells/year.	Average drilling rate ≈ 1,900 wells/year.	Average drilling rate ≈ 2,000 wells/year.
Mid-term (2018 – 2035)	Average drilling rate ≈ 1,700 wells/year. Drilling rate slowly declines in Garfield County and shifts to Rio Blanco County.	Average drilling rate ≈ 2,125 wells/year to account for additional activity in the northern Piceance Basin. Approx. 65,000 operational wells by 2035.	Average drilling rate ≈ 2,300 wells/year to provide thermoelectric power to the oil shale industry for start-up.
Long-term (2036 – 2050)	Drilling activity slowly declines to ~1,100 well/year by 2050.	Drilling activity slowly declines to ~1,500 well/year by 2050.	Drilling activity slowly declines to ~1,700 well/year by 2050.

Direct Water Demands for Natural Gas Production (af/year)

Time Frame	Level of Development – Natural Gas Low	Medium	High
Short-term (2007 – 2017)	2007: 2,965 2017: 4,292	2007: 3,133 2017: 4,880	2007: 3,165 2017: 5,230
Mid-term (2018 – 2035)	2018: 4,168 2035: 3,975	2018: 5,044 2035: 4,874	2018: 5,437 2035: 5,276
Long-term (2036 – 2050)	2036: 3,869 2050: 2,834	2036: 4,769 2050: 3,285	2036: 5,171 2050: 3,686

Indirect Water Demands for Natural Gas Production (af/year)

Time Frame	Level of Development – Natural Gas: Low	Medium	High
Short-term (2007 – 2017)	6,600 to 9,400	6,600 to 10,200	6,700 to 10,800
Mid-term (2018 – 2035)	8,300 to 9,400	10,000 to 10,800	10,900 to 11,400
Long-term (2036 – 2050)	6,100 to 8,200	8,100 to 10,300	8,900 to 11,100

Coal Industry Production Scenarios

Level of Development - Coal

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	Red Cliff mine begins producing 2.5 million tpy by 2011. Total production holds steady at 20.5 million tpy.	No change from low/near-term production scenario.	No change from low/near-term production scenario.
Mid-term (2018 – 2035)	Production rate holds steady at 20.5 million tpy.	Red Cliff mine begins producing 8 million tpy by 2018. Total production holds steady at 26 million tpy.	No Change from Medium/Mid-Term production scenario.
Long-term (2036 – 2050)	Production rate holds steady at 20.5 million tpy.	No change from medium/mid-term production scenario.	Add 1 coal gasification or liquefaction plant in northwest Colorado processing approximately 4 million tons of coal per year. Total coal production of 30 million tpy.

Direct Water Demands for Coal Production (af/year)

Level of Development - Coal

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	1,213	1,213	1,213
Mid-term (2018 – 2035)	1,213	1,538	1,538
Long-term (2036 – 2050)	1,213	1,538	5,063

Indirect Water Demands for Coal Production (af/year)

Time Frame	Level of Development - Coal Low	Medium	High
Short-term (2007 – 2017)	1,100	1,400	1,400
Mid-term (2018 – 2035)	1,100	1,400	1,400
Long-term (2036 – 2050)	1,100	1,400	2,400

Uranium Industry Production Scenarios

Level of Development - Uranium

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	No uranium mining within project area.	No uranium mining within project area.	1 underground uranium mine.
Mid-term (2018 – 2035)	No uranium mining within project area.	1 underground uranium mine.	1 underground uranium mine.
Long-term (2036 – 2050)	No uranium mining within project area.	1 underground uranium mine.	2 underground uranium mines: 1 in Mesa County and 1 in Moffat County.

Direct Water Demands for Uranium Production (af/year)

Level of Development - Uranium

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	No uranium mining within project area.	No uranium mining within project area.	62
Mid-term (2018 – 2035)	No uranium mining within project area.	62	62
Long-term (2036 – 2050)	No uranium mining within project area.	62	124

Thermoelectric Power Generation Water Demands for Natural Gas, Coal and Uranium Production (af/year)

Level of Development

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	Natural Gas: 4,354 Coal: 755 Uranium: 0	Natural Gas: 5,230 Coal: 764 Uranium: 3	Natural Gas: 5,428 Coal: 764 Uranium: 3
Mid-term (2018 – 2035)	Natural Gas: 5,827 Coal: 755 Uranium: 0	Natural Gas: 8,309 Coal: 958 Uranium: 3	Natural Gas: 9,012 Coal: 958 Uranium: 3
Long-term (2036 – 2050)	Natural Gas: 5,049 Coal: 755 Uranium: 0	Natural Gas: 7,501 Coal: 958 Uranium: 3	Natural Gas: 8,220 Coal:1,124 Uranium: 6

Summary of Total Water Demands for Natural Gas, Coal and Uranium Production (af/year)

Level of Development

Time Frame	Low	Medium	High
Short-term (2007 – 2017)	Natural Gas: 18,050 Coal: 3,070 Uranium: 0	Natural Gas: 20,300 Coal: 3,380 Uranium: 3	Natural Gas: 21,460 Coal: 3,380 Uranium: 65
Mid-term (2018 – 2035)	Natural Gas: 19,200 Coal: 3,070 Uranium: 0	Natural Gas: 23,980 Coal: 3,900 Uranium: 65	Natural Gas: 25,690 Coal: 3,900 Uranium: 65
Long-term (2036 – 2050)	Natural Gas: 15,635 Coal: 3,070 Uranium: 0	Natural Gas: 21,085 Coal: 3,900 Uranium: 65	Natural Gas: 23,010 Coal: 8,590 Uranium: 130

Total Water Demands include Direct, Indirect and Thermoelectric

Indirect Water Use Estimates for Energy Development

Sector	Indirect Water use (acre-feet/year)
Oil Shale	
Construction and Production	8,800
Electrical Energy	500
Natural Gas	8,900 to 11,100
Uranium	Not significant
Coal	2,400

Note: Estimates of indirect water use for natural gas, uranium and coal are the same as in Phase 1

Duration of Phases (Years)

Should this be moved up after Direct Water Use bullets?

	In-situ Retorting	Above-Ground Retorting
Construction/Pre-production	2.5	4
Production	6.5	25
Reclamation	5.5	4
Total	14.5	33

Regional Population Increase due to Oil Shale Development

	Number of people
Garfield County	8,748
Mesa County	2,876
Rio Blanco County	36,584
Total Population	48,208